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IN THE

Supreme Court of the United States

OCTOBER TERM, 1983

HUBERT H. HUMPHREY, III, Attorney General of the State of Minnesota; MINNESOTA PUBLIC UTILITIES COMMISSION; and MINNESOTA DEPARTMENT OF PUBLIC SERVICE,

Petitioners,

vs.

NORTHERN STATES POWER COMPANY, and MINNESOTA PUBLIC INTEREST RESEARCH GROUP,

Respondents.

APPENDIX TO PETITION FOR WRIT OF CERTIORARI TO THE SUPREME COURT OF THE STATE OF MINNESOTA

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1984—Northwest Brief Printing Co., 3010 2nd St. No., Minneapolis 55411—588-7506

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APPENDIX

STATE OF MINNESOTA
IN SUPREME COURT
CX-82-1130, C1-82-1131, CX-82-1354

Northern States Power Company, petitioner,
Respondent,

v.

Minnesota Public Utilities Commission,
Appellant (C1-82-1131),

and

Minnesota Department of Public Service, intervenor,
Appellant (C1-82-1131),

Minnesota Office of Consumer Services, intervenor,
Appellant (CX-82-1130),

City of Saint Paul, et al.,
Intervenors-Respondents Below,

Minnesota Public Interest Research Group, intervenor,
Appellant (CX-82-1354).

ORDER

This court having heard and considered en banc the petition for rehearing in the above-entitled matter,

IT IS ORDERED that:

1. The opinion filed herein on December 9, 1983, is hereby withdrawn and the attached opinion is substituted;

2. Except as above indicated, the petition for rehearing is denied;

3. Respondent is not allowed attorney fees on this petition pursuant to Rule 140, Rules of Civil Appellate Procedure

DATED: January 27, 1984.

BY THE COURT

/s/ Glenn E. Kelley, Associate Justice

Endorsed
Filed January 27, 1984
Wayne Tschimperle, Clerk
Minnesota Appellate Courts

SYLLABUS

The acceptance by the Federal Energy Regulatory Commission of a filed amended coordinating agreement between Minnesota and Wisconsin electrical power utilities established a wholesale rate which must be considered by the Minnesota Public Utilities Commission as an expense of power purchased in setting rates for Minnesota Retail electric power purchases.

Affirmed.

Heard, considered and decided by the court en banc.

OPINION

KELLEY, Justice.

As the result of the abandonment of plans to construct the Tyrone nuclear power plant near Durand, Wisconsin, Northern States Power Company (NSP)[1] sustained sub-

[1]Two utilities are involved. Respondent Northern States Power Company (NSP) is a Minnesota corporation which supplies electricity to retail and wholesale customers in Minnesota, North Dakota and South Da-

stantial cancellation losses. In 1970, NSP and NSP-W filed with the Federal Power Commission (now known as the Federal Energy Regulatory Commission or FERC) a "Coordinating Agreement" (CA). Following incurrence of the abandonment losses at the Tyrone plant, NSP and NSP-W filed with FERC an amendment to the CA. The amendment sought to allocate the Tyrone abandonment losses between the two companies. In substance, FERC approved the amendment. Thereafter, NSP instituted this proceeding before the Minnesota Public Utilities Commission (MPUC) to obtain approval of proposed increase in retail rates in Minnesota to recoup the portion of the cancellation losses attributable to its Minnesota customers The Minnesota hearing examiner, finding that the CA and its amendment established a wholesale rate schedule within the exclusive jurisdiction of FERC and that the parties could not attack the reasonableness of those rates prescribed by FERC, recommended that NSP be allowed to include Tyrone losses as expenses for power purchased. The MPUC reversed the hearing examiner. On appeal to the Ramsey County District Court, the court reversed the MPUC. Various interested parties appeal to this court.[2] Because we conclude that the amendment to the CA filed with and approved by FERC established a wholesale rate within the exclusive jurisdiction of FERC, we affirm.

kota. Because Wisconsin law requires all public utilities conducting business in Wisconsin to be domestic corporations (Wis. Stat. §196.53 (1979-80)), Northern States Power-Wisconsin (NSP-W) is a wholly owned subsidiary of NSP which provides retail and wholesale service to Wisconsin customers. The two utilities operate an "integrated" system in which transmission facilities are interconnected and operated in synchronism.

[2]The appealing parties are the Minnesota Utilities Commission (MPUC), the Minnesota Office of Consumer Services (MOCS), the Minnesota Department of Public Services (MDPS), and the Minnesota Public Interest Research Group (MPIRG). For convenience, these parties will be referred to collectively as appellants.

The MPUC is required to treat the abandonment losses allocated under the amendment as expenses for power purchased in determining retail rates to be charged Minnesota ratepayers.

During the late 1960's, in response to electric power demand projections, NSP and NSP-W instituted plans for construction of two nuclear power plants in Wisconsin. Because of substantial changes in the electric power demand outlook subsequent to initial projections, the final Tyrone project was to be a single nuclear power plant. Each utility originally had roughly indivisible equal ownership in the project together with other utilities.[3] Since Wisconsin prohibited utility ownership by foreign corporations, NSP-W "bought out" NSP's interest in the project.

In 1977, the Federal Nuclear Regulatory Commission issued a construction permit for Tyrone.[4] NSP-W sought construction approval from the Wisconsin Public Service Commission (WPSC). In a hearing before the WPSC, that commission established three "need tests," at least one of which had to be met by the utility before the WPSC would approve the proposed Tyrone construction. Two of the tests examined the need for the project in light of Wisconsin power demands only. The third test focused on the economic and environmental impact of the project. Subsequently, in rejecting NSP-W's application for certification to build Tyrone, the WPSC found the company had "failed" all three of the "need tests." Thereafter, the Ty-

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[3]Other utilities with an ownership interest were: Cooperative Power Association (17.4%), Dairyland Power Cooperative (13.0%) and Lake Superior District Power Company (2.0%).

[4]The Nuclear Regulatory Commission must issue a license before construction may commence on a nuclear facility. After that license is issued, the utility must secure, in addition, construction approval from the relevant state regulatory bodies.

rone project was abandoned. Its abandonment resulted in substantial losses to NSP-W and to NSP.[8] On August 24, 1979, NSP and NSP-W filed with FERC an amendment to the CA. The amendment was designed to allocate Tyrone abandonment costs in accordance with the standard allocation formula used for other costs under the initial CA. Following a hearing at which the MPUC and the Minnesota attorney general's office intervened, the federal administrative law judge on December 4, 1980, approved the amendment to the CA. *See* 13 [Oct-Dec 1980 Transfer Binder] FERC (CCH) ¶63,049 (1980). His decision was affirmed by FERC in December 1980. *See* 17 [Oct-Dec 1980 Transfer Binder] FERC (CCH) ¶ 61,196 (1981). The MPUC and the South Dakota Public Utilities Commission appealed to the United States Eighth Circuit Court of Appeals. That court affirmed FERC's approval of the amended CA. *See South Dakota Public Utilities Commission v. Federal Energy Regulatory Commission,* 690 F.2d 674 (8th Cir. 1982).

In this action, NSP is attempting to have its retail ratepayers in Minnesota pay for the Minnesota proportionate share of NSP's expense arising out of the Tyrone abandonment. In essence, NSP claims that FERC's approval of the amended CA resulted in the establishment of an interstate wholesale rate. Therefore, it asserts, the MPUC must allow NSP to pass the Tyrone losses through to re-

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[8]In 1970, NSP and NSP-W had entered into a Coordinating Agreement which was filed with the Federal Power Commission (now known as the Federal Energy Regulatory Commission or FERC). In essence, under the CA filed in 1970, NSP and NSP-W shared the systematic cost of power generation in a ratio roughly proportionate to ultimate use by the customers of each. Such costs were roughly allocated 87% to NSP and 13% to NSP-W. Thus, abandonment losses were sustained by NSP, even though it had "sold" its individual interest in the Tyrone plant.

tail ratepayers.[6] The appellants, on the other hand, contend that the Wisconsin Public Service Commission decision which led to the abandonment was a "parochial" one based on considerations of Wisconsin needs alone. More importantly, appellants assert that FERC's approval of the amended CA was merely an allocation of costs between NSP and NSP-W and that, therefore, FERC's approval did not preempt the MPUC's authority to review expenses allocated by the amended CA for the purpose of retail ratemaking.

If the amended CA constitutes a FERC-approved wholesale rate, the MPUC has no power to reexamine the reasonableness of the costs underlying the wholesale rate.[7] On the other hand, if the amended CA was merely a loss allocation between the two utilities, NSP's Tyrone loss is

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[6]NSP is seeking to "pass through" the Tyrone losses to retail ratepayers in the four states where it has retail customers. After the North Dakota Public Service Commission refused NSP's application, the North Dakota Supreme Court ruled that the FERC order approving the amended CA precluded that state's regulatory agency from examining the matter further. *See Northern States Power Co. v. Hagen*, 314 N.W.2d 32 (N.D. 1981). Thereafter, North Dakota rates reflecting Tyrone losses began on January 17, 1982. South Dakota, by order of the public utilities commission dated April 27, 1983, has agreed to allow recovery of the amortization calculated for the period commencing October 1, 1981. Wisconsin rates reflecting Tyrone losses were effective April 21, 1981.

[7]*See Montana-Dakota Utilities Co. v. Northwestern Public Service Co.*, 341 U.S. 246, 251-52 (1951). The court there said:

> To reduce the abstract concept of reasonableness to concrete expression in dollars and cents is the function of the [Federal Power] Commission [the predecessor of FERC].
>
> * * * *
>
> We hold that the right to a reasonable rate is the right to the rate which the Commission files or fixes, and that, except for review of the Commission's orders, the courts can assume no right to a different one on the ground that, in its opinion, it is the only or the more reasonable one.

See also Arkansas Lousiana Gas Co. v. Hall, 453 U.S. 571 (1981); *Narragansett Electric Co. v. Burke*, 119 R.I. 559, 381 A.2d 1358 (1977), *cert. denied* 435 U.S. 972 (1978).

not necessarily a proper expense for purchased power. In such case, the MPUC has the authority to determine that either the retail ratepayers or NSP shareholders will bear the loss. *See* 16 U.S.C. § 824(b)(1) (1982); Minn. Stat. §216B.03 (1982). *Cf. Minneapolis Street Railway Co. v. City of Minneapolis,* 251 Minn. 43, 86 N.W.2d 657 (1957) (street railway abandonment costs).

We commence by noting our scope and standard of review in a rate case.[8] We presume the agency's decision (here, the decision of the MPUC) is correct, but the court may reverse an agency decision if the decision was affected by an error of law. *See Reserve Mining Co. v. Herbst,* 256 N.W.2d 808, 824-25 (Minn. 1977); *Resident v. Noot,* 305 N.W.2d 311, 312 (Minn. 1981); *State ex rel. Spurck v. Civil Service Board,* 226 Minn. 240, 249, 32 N.W.2d 574, 580 (1948).

NSP and NSP-W are engaged in the transmission and sale of electricity in interstate commerce. They are, therefore, subject to regulation by both state and federal agencies. State utilities commissions may regulate only intrastate wholesale and retail rates for the sale of power to consumers but have no regulatory power over wholesale interstate transactions. *Public Utilities Commission of*

[8]Minn. Stat. §14.69 (1982) provides:

> In a judicial review under sections 14.63 to 14.68, the court may affirm the decision of the agency or remand the case for further proceedings; or it may reverse or modify the decision if the substantial rights of the petitioners may have been prejudiced because the administrative finding, inferences, conclusion, or decisions are:
> (a) In violation of constitutional provisions; or
> (b) In excess of the statutory authority or jurisdiction of the agency; or
> (c) Made upon unlawful procedure; or
> (d) Affected by other error of law; or
> (e) Unsupported by substantial evidence in view of the entire record as submitted; or
> (f) Arbitrary or capricious.

Rhode Island v. Attleboro Steam & Electric Co., 273 U.S. 83 (1927). In 1935, the United States Congress enacted the Federal Power Act.[9] Section 201 of the Federal Power Act describes the federal-state spheres in utility regulation.[10] In *Federal Power Commission v. Southern California Edison Co.*, 376 U.S. 205 (1964), the United States Supreme Court determined that in enacting the Federal Power Act Congress intended to vest exclusive federal authority to regulate interstate wholesale utility rates in the Federal Power Commission (prodecessor to FERC). Moreover, that Court indicated Congress intended to draw a "bright line," easily ascertainable, between state and federal jurisdiction making unnecessary a case-by-case analysis. *Federal Power Commission v. Southern California Edison Co.*, 376 U.S. at 215-16. Thus, FERC's jurisdiction is

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[9]The regulatory authority created under the Federal Power Act was transferred to FERC in 1977 with the establishment of the Department of Energy. Department of Energy Organization Act, Pub. L. No. 95-91, §402, 91 Stat. 565, 583 (1977) (codified at 42 U.S.C. §7172 (Supp. V 1981)).

[10]Section 201 of the Federal Power Act provides:

> (a) It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation * * * and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.
>
> (b) (1) The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but * * * shall not apply to any other sale of electric energy * * *.

16 U.S.C. §824 (1982).

plenary and extends to all wholesale sales in interstate commerce.[11]

On the other hand, the MPUC's jurisdiction is limited to regulation of intrastate retail rates. Minn. Stat. § 216B.03 (1982) provides that the MPUC shall establish "just and reasonable" retail rates. In order to establish "just and reasonable" retail rates, the MPUC must consider the right of the utility and its investors to a reasonable return, while at the same time establishing a rate for consumers which reflects the cost of service rendered plus a "reasonable" profit for the utility. *Narragansett Electric Co. v. Burke,* 119 R.I. 559, 381 A.2d 1358 (1977), *cert. denied* 435 U.S. 972 (1978). To accomplsh this purpose, the MPUC must ascertain the operating expenses, or cost of service, of the utility. In general, regulators have allowed recovery of investment and cancellation costs of abandoned projects through rates. Utilities have usually been allowed recovery of annual amoritization expense from ratepayers as a component of total cost of service. Sommers, *Recovery of Electric Utility Losses from Abandoned Construction Projects,* 8 Wm. Mitchell L. Rev. 363, 364 (1982). Therefore, if the amended CA providing that

[11]Appellants contend that FERC's authority over interstate wholesale rates has been modified by *Arkansas Electric Cooperative Corp. v. Arkansas Public Commission,* 103 S.Ct. 1905 (1983). The United States Supreme Court in *Arkansas Electric* held that a state public utility commission could examine wholesale rates of an interstate electric cooperative because, although the Rural Electrification Act did contemplate some review of wholesale cooperative electric rates by the Rural Electrification Administration, the review was intended to be non-exclusive since that Act itself presupposed some state review of wholesale rates of power cooperatives. 103 S.Ct. at 1911-14. The United States Supreme Court also indicated that if Arkansas Electric Cooperative Corporation were not a rural power cooperative, the wholesale rates it charges to its members would be subject exclusively to federal regulation. 103 S.Ct. at 1911. Accordingly, the Court's holding in *Arkansas Electric* is irrelevant to FERC's plenary jurisdiction to regulate interstate wholesale rates of investor-owned utilities.

NSP share approximately 87% of the Tyrone losses served to establish a wholesale rate, the MPUC had no jurisdiction to determine the reasonableness of that loss allocation. Accordingly, we must make the legal determination whether the CA, as amended, established such a wholesale rate.

In August 1979, a decision was made to abandon the Tyrone project. In the same month NSP and NSP-W filed with FERC an amendment to the CA which was designed to allocate the Tyrone abandonment costs generally in accordance with the formula used for allocation of other costs pursuant to the original CA.[12] Following the filing of the amendment to the CA and while litigation was proceeding through the federal administrative review procedures culminating finally in *South Dakota Public Utilities Commission v. Federal Energy Regulatory Commission*, 690 F.2d 674 (8th Cir. 1982), NSP sought approval to raise retail rates in Minnesota.

The Minnesota hearing examiner conducted extensive hearings. He concluded that the amended CA established a formula wholesale rate. He therefore recommended that NSP be allowed to include the Tyrone losses as expenses of power purchased in the test year.[13] So included, the "ex-

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[12]The final NSP share of the abandonment loss appears to be approximately $67 million. FERC Opinion No. 134, FERC Docket No. ER 79-616, 17 [Oct-Dec 1981 Transfer Binder] FERC (CCH) ¶ 61,196 at 61,379 (December 3, 1981). NSP proposed to allocate its 87% share of the loss 75% to Minnesota and the remainder to North Dakota and South Dakota. It also proposed that, of the 75% assigned to Minnesota, 96.6% would be apportioned to retail customers and 3.4% to wholesale customers.

[13]The "test year" is a period of time for which data regarding the company's revenues and expenses are collected and examined. Based on this information, the regulatory body determines a "just and reasonable" rate to be charged for the utility's services. *See generally* 1 A.J.G. Priest, *Principles of Public Utility Regulation* 45 (1969). Since utilities are, of course, allowed to recoup expenses, inclusion of an item as a test year expense will result in a corresponding rate increase. *See generally Mississippi River Fuel Corp. v. Federal Power Commission*, 163 F.2d 433, 437 (D.C.Cir. 1947).

penses" would be passed on to the ratepayer in the form of higher retail rates. The hearing examiner, rejecting the arguments now being advanced by appellants before this court, held that FERC had sole jurisdiction to determine whether NSP had acted imprudently, unwisely, and in disregard of the rights of the public.[14]

On appeal, the MPUC rejected NSP's contention that FERC's order in Docket No. ER79-616 automatically required the MPUC to allow NSP to treat its payments to NSP-W for the Minnesota company's share of the Tyrone losses as a reasonable operating expense to be borne by Minnesota ratepayers. By its order, *In re Petition of NSP*, MPUC Docket No. E-002/GR-80-316, the MPUC held that it had exclusive jurisdiction to determine what impact the Tyrone abandonment expenses should have on rates charged to Minnesota ratepayers. It concluded that FERC's approval of the amended CA was not a valid wholesale rate and therefore was not binding on the MPUC. In essence, the MPUC was of the opinion the CA was merely an allocation of costs between the two utilities.

On appeal to the district court pursuant to Minn. Stat. § 216B.52 (1982), the MPUC order was reversed. The district judge relied on the grounds stated by the Supreme Court of North Dakota in *Northern States Power Co. v. Hagen*, 314 N.W.2d 32 (N.D. 1981). The North Dakota court had held the FERC order accepting the amended CA precluded that state's regulatory authority from examing the matter further.[15] The North Dakota court noted that

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[14]The Minnesota hearing examiner noted, as did the federal administrative law judge, that appellants' claim that the decision of the Wisconsin Public Service Commission was "parochial" was irrelevant.

[15]*Northern States Power Co. v. Hagen*, 314 N.W.2d 32 (N.D. 1981), involved the identical issue presented here—whether the North Dakota Public Service Commission in a retail rate proceeding had jurisdiction to

NSP is required by the FERC order to pay a fixed wholesale rate for electricity to NSP-W which includes the amortization of the Tyrone loss. *Hagen,* 314 N.W.2d at 37. It went on to hold that since the North Dakota Public Service Commission had no direct jurisdiction over interstate wholesale rates, it would undermine the supremacy clause and the preemption doctrine for the North Dakota Public Service Commission to indirectly assert jurisdiction over the wholesale rates by again investigating the reasonableness of the underlying costs in a proceeding involving retail rates. *Hagen,* 314 N.W.2d at 38.

On this appeal appellants basically argue that the amended CA simply allocated the abandonment loss between the two companies. Once the loss was placed on the corporate books, then each company independently tried to recoup the loss in any way possible. Thus, appellants claim, the Tyrone loss is not necessarily a proper expense for purchased power but is rather a financial burden which the MPUC has the authority and jurisdiction to force either the ratepayers or NSP shareholders to bear.

FERC accepted the amended CA as a "rate." As to NSP, it denominated it "Rate Schedule No. 375" and as to NSP-W, "Rate Schedule No. 53." Those designations, however, are not necessarily determinative.[10] The definition

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reexamine the reasonableness of all of NSP's retail expenses—despite the fact that NSP's amortization abandonment losses, a part of those expenses were previously allowed as part of the interstate wholesale purchase on the basis of interstate wholesale rates filed with FERC.

[10]When FERC uses the term "rate," it uses the definition found in 18 C.F.R. § 35.2(b) (1983) as follows:

> *Rate Schedule.* The term "rate schedule" as used herein shall mean a statement of (1) electric service as defined in paragraph (a) of this section, (2) rates and charges for or in connection with that service, and (3) all classifications, practices, rules, regulations or contracts which in any manner affect or relate to the aforementioned service, rates, and charges.

of "rate schedule" obviously includes wholesale rates but appears broad enough to encompass other subjects.

Appellants rely heavily on wording in the initial decision of the federal administrative law judge to support the contention that the allocation of the Tyrone loss did not establish a wholesale rate. The administrative law judge said:

> [Allocation of Tyrone loss via the CA] may not automatically govern the ratemaking consequences either at the federal (resale rates) or state (retail rates) level. In recognition of this, NSP states that it is willing to make such reports and filings which the federal and state regulatory bodies may require, within their jurisdictional authority, to reflect the allocation of the loss between the two NSP Companies in their respective resale and retail rates.

Initial Decision on Nuclear Plant Cancellation Loss, FERC Docket No. ER79-616, 13 [Oct-Dec 1980 Transfer Binder] FERC (CCH) ¶ 63,049 at 65,288 (December 4, 1980) (footnote omitted). NSP answers that appellants draw too much from the federal administrative law judge's language and asserts that this statement is nothing more than a recognition by the administrative law judge that he could not, in fact, dictate ultimate retail rates. That language, standing alone, would tend to dispel any sense that the MPUC would be required to "rubber stamp" the federal allocation decision in a subsequent retail rate hearing.

In a totally separate FERC proceeding, NSP-W sought to raise its wholesale rates to certain full-requirement customers located in Wisconsin. These included a number of municipal corporations to which NSP-W sells power for

resale. Part of the requested increase was prompted by an attempt to pass through some of the Tyone losses. In discussing FERC Docket No. ER79-616 (the FERC case which ultimately approved the amended CA), FERC's opinion characterized the purpose of it as follows:

> The hearing in Docket No. ER79-616 was established to determine: (1) whether the amortization is propper; (2) whether the NSP-Minn/NSP-Wis Coordination Agreement affords a reasonable method of allocating amortization; and (3) whether the length of the amortization period is appropriate.

Northern States Power Company (Wisconsin), Docket No. ER80-181, 10 [Jan-March 1980 Transfer Binder] FERC (CCH) ¶ 61,223 at 64,421 (March 7, 1980).

However, FERC later commented on the effect of the amended CA in its order denying rehearing and request for summary disposition and dismissal of a subsequent amendment to the CA. Northern States Power Company (Minnesota), Docket No. ER83-89-001, 23 [April-June 1982 Transfer Binder] FERC (CCH) ¶ 61,026 (April 6, 1983). In that case, NSP filed an additional amendment to the CA affecting NSP, NSP-W and Lake Superior District Power Company. The purpose of this amendment was to modify the methodology used in calculating fixed charges shared among the three companies. The MPUC and the Minnesota attorney general intervened, claiming, as here, that the amended CA was merely a cost allocation device and not a wholesale rate. In rejecting that contention, the FERC order stated:

> [T]he coordinating agreement does establish rates and charges, albeit through formula rates, for the

> use of generation and transmission facilities which have been dedicated to coordinated operation. ***
>
> The [CA] establishes the means by which the interstate transfer of power between the companies occurs and the intercompany charges for such transactions. ***
>
> By making a determination as to the appropriate return on equity established by [the CA], we are not purporting to establish the return for retail rates. Our determination will only affect retail rates to the extent that the state is required to treat the allocated costs as expenses for purposes of determining the retail rates. Such a situation is not unique and is typical to the entire wholesale-retail regulatory process.

Id. at 61,066. Thus, it seems clear to us that by FERC's own expression in these cases it considered the approval of the amendment to the CA as establishing a formula wholesale rate, the reasonableness of which cannot be relitigated in a retail rate proceeding before a state utilities commission.

Appellants further contend that the amendment to the CA cannot be a FERC-approved wholesale rate because, they claim, FERC has no power to alter a rate retroactively. In the instant case, NSP's amendment to the CA was filed with FERC on August 24, 1979. By the terms of the filing and under the final FERC order, the amendment was effective as of March 6, 1979, the date of the Tyrone abandonment. Appellants here claim that since FERC gave the amended CA retroactive effect, such fact demonstrates it cannot be a wholesale rate. The statute, 16 U.S.C.

§ 824d(d) (1982), provides that FERC may waive the requirement that rates become effective in futuro. *See City of Piqua, Ohio v. Federal Energy Regulatory Commission,* 610 F.2d 950, 952-54 (D.C. Cir. 1979). We conclude the retroactivity of FERC's order amending the CA does not preclude it from establishing a wholesale rate.

Next, appellants contend that under the terms of the amended CA there is no "sale for resale," and, therefore, it cannot constitute a wholesale rate. Under the Federal Power Act, the sale of energy at wholesale requires a "sale of electric energy to any person for resale." 16 U.S.C. § 824(d) (1982). Appellants argue that since NSP-W has no substantial baseload capacity—generating plants—in Wisconsin, there cannot be wholesale sales from NSP-W to NSP. In this connection, appellants also contend there is no "separate transaction," which is the hallmark of a wholesale sale. *United States v. Public Utilities Commission of California,* 345 U.S. 295, 318 (1953). They suggest that the occurrence of any "sale" is existentially denied because the amount of "sales" and "rates" at which they are made cannot be determined from the amended CA. Finally, they contend there is no wholesale transaction because payments under the amended CA are discretionary—that is, there is no "fixed" rate.[17]

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[17]The MPUC and the Minnesota Department of Public Service contend, in addition, that inasmuch as the Tyrone costs were incurred by NSP-W, a subsidiary of NSP, they are affiliate costs and that the MPUC has jurisdiction to question the propriety of those costs. In so doing they rely on telephone rate cases *Smith v. Illinois Bell Telephone Co.,* 282 U.S. 133 (1930), and *Northwestern Bell Telephone Co. v. State,* 299 Minn. 1, 216 N.W.2d 841 (1974). Without dispute, the MPUC may question the propriety of transactions between affiliated companies which are not otherwise subject to federal regulation in the area. However, such is not the case when considering wholesale power rates under the jurisdiction of FERC. Congress recognized in enacting the Federal Power Act, 16 U.S.C. §§ 791a-828c (1982), and the Public Utility

We acknowledge that electricity is a fungible commodity. It is difficult, if not impossible, in an integrated and synchronized electrical power system to determine the precise source of an electrical flow. It is clear that FERC's jurisdiction is broad enough to govern "sales" without the need to resort to tracing the source and end use of electiricty. It is sufficient that some electrical power conceivably flows in interstate commerce in the form of a wholesale sale. *See Federal Power Commission v. Florida Power & Light Co.*, 404 U.S. 453, 466-69 (1972). Thus, the location of baseload generating plants is not critical. Moreover, NSP-W does generate electricity in Wisconsin so "sales" could occur from NSP-W to NSP, even if they are not detected at a particular instant in time.[18] Finally, we note a formula rate as established by a CA is just as much a rate as any other kind of rate. We conclude, therefore, appellants' argument that the amended CA does not establish a "sale for resale" and therefore cannot constitute a wholesale rate is without merit.

We hold that FERC's approval of the amended CA constituted the establishment of a wholesale rate. While that determination does not directly establish the return for retail rates, which is in the exclusive jurisdiction of the

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Holding Company Act of 1935, 15 U.S.C. §§ 79-79z-6 (1982), that affiliate power transactions "are not susceptible of effective control by any State." 15 U.S.C. § 79a(a) (1982). *Narragansett Electric Co. v. Burke*, 119 R.I. 559, 381 A.2d 1358 (1977), *cert. denied* 435 U.S. 972 (1978), in fact, involved wholesale transactions between affiliated companies. Transactions, such as this one, between affiliated power companies appear to be precisely the type of transactions that Congress sought to regulate by enactment of the Federal Power Act and the Public Utility Holding Company Act of 1935.

[18]For example, NSP-W's capacity includes a certain amount of hydro-power generating capacity. Since hydro-power is a very low cost option, it is presumably used very often, though it is not technically considered a baseload facility.

MPUC, the state utilities commission is required to treat the allocated abandonment costs as expenses for power purchased in determining the retail rates. Accordingly, we affirm the order and judgment of the district court.

Affirmed.

STATE OF MINNESOTA — DISTRICT COURT
County of Ramsey — Second Judicial District

File No. 452088

NORTHERN STATES POWER COMPANY,
Petitioner-Appellant,

vs.

MINNESOTA PUBLIC UTILITIES COMMISSION,
Respondent,

and

MINNESOTA DEPARTMENT OF PUBLIC SERVICE, MINNESOTA OFFICE OF CONSUMER SERVICES, CITY OF SAINT PAUL, MINNESOTA SENIOR FEDERATION, UNITED HANDICAPPED FEDERATION, and MINNESOTA PUBLIC INTEREST RESEARCH GROUP,
Intervenors-Respondents.

ORDER

Before the Court is the appeal of Northern States Power Company from the Order of the Minnesota Public Utilities Commission dated April 30th, 1981, and from its Order

Denying Rehearing dated June 17th, 1981. Notices of the proceeding were mailed to 42 organizations and individuals. Following the submission of briefs to the Court, oral argument was held on June 7, 1982. The following appeared by way of briefs and/or at oral argument:

Samuel L. Hanson and Leonard J. Keyes of the law firm of Briggs & Morgan, 2452 IDS Center, Minneapolis, Minnesota 55402, and David L. Lawrence, Attorney-at-Law, 414 Nicollet Mall, Minneapolis, Minnesota 55401, on behalf of the petitioner-appellant, Northern States Power Company; Rodney A. Wilson and Kenneth A. Nickolai, Special Assistants to the Attorney General, 720 American Center Building, 150 East Kellogg Boulevard, Saint Paul, Minnesota 55101, on behalf of the respondent, Minnesota Public Utilities Commission; Jean E. Heilman, Assistant Attorney General, 720 American Center Building, 150 East Kellogg Boulevard, Saint Paul, Minnesota 55101, on behalf of intervenor-respondent, Minnesota Department of Public Service. Richard G. Evans, Special Assistant Attorney General, 1100 Bremer Tower, Saint Paul, Minnesota 55101, on behalf of intervenor-respondent, Minnesota Office of Consumer Services; James D. Miller, Attorney-at-Law, 2412 University Avenue South East, Minneapolis, Minnesota 55414, on behalf of intervenor-respondent, Minnesota Public Interest Research Group.

The Court having heard arguments of counsel, and upon the briefs, files and records herein:

IT IS ORDERED:

That portion of the Order of the Minnesota Public Utilities Commission dated April 30, 1981, relating to the Tyrone abandonment is reversed. The Commission is directed to include in the operating expenses of petitioner-appel-

lant Northern States Power Company the amount of $10,-928,000, reduced appropriately to reflect the increased amortization period approved by the Federal Energy Regulatory Commission.

LET JUDGMENT BE ENTERED ACCORDINGLY.

The following Memorandum is made a part of this Order.

/s/ Charles A. Flinn, Jr.
Judge of District Court

DATED: This 3 day of August, 1982.

MEMORANDUM

This is an appeal by petitioner-appellant Northern States Power Company (hereinafter NSP) from an Order of the respondent, Minnesota Public Utilities Commission (hereinafter PUC). This Order eliminated from certain rate increases requested by NSP, the sum of $10,928,000 representing the increased cost of purchase power paid to NSP's subsidiary, NSP Wisconsin (hereinafter NSP-W) for wholesale transactions under wholesale rates established by the Federal Energy Regulatory Commission (hereinafter FERC) That amount represents a portion of the losses incurred by NSP-W, because of the abandonment of the Tyrone Energy Project. The total losses will be allocated among the four states where NSP does business, North and South Dakota, Minnesota and Wisconsin.

Proceedings regarding the allocation of these costs have been held before regulatory bodies in Minnesota, Wisconsin and North Dakota before a federal administrative

law judge, FERC and the identical case was recently decided by the North Dakota Supreme Court. The case was also fully heard and a decision rendered by Hearing Examiner Richard DeLong, who heard the matter on behalf of the Minnesota PUC. An appeal of the FERC matters is also pending in the Eighth Circuit Court of Appeals. Briefs, reply briefs and further reply briefs have been filed with this court and extensive oral arguments have been presented by all interested parties. The situation is well-described by Hearing Examiner DeLong, who wrote in his decision: "Although the incapacity of the Tyrone Plant to generate one kilowatt of electricity has long been assured, its capacity to generate both reasoned and emotional controversy has not been stilled" (Report of the Hearing Examiner, Tyrone Abandonment Discussion).

The facts surrounding this controversy are basically not in dispute and are detailed in the briefs, the decisions of the hearing examiner and the PUC, as well as the opinion of the North Dakota Supreme Court in *Northern States Power vs. Hagen*, 314 N.W.2d 32, (N.D., 1981).

NSP, a Minnesota corporation, and NSP-W, its wholly owned subsidiary, operate an integrated power supply system. NSP serves retail and wholesale customers in Minnesota, North and South Dakota and NSP-W provides service in Wisconsin. The generation and transmission of power is coordinated as a single power supply system. Within this system, the companies interchange or transmit electric power at wholesale in interstate commerce. Such exchanges of power fall within the jurisdiction of FERC. In complying with FERC's rules and regulations, NSP and NSP-W have for many years submitted their arrangement and charges to FERC under a formula rate contract known as

a Coordinating Agreement. The contract, which was originally dated October 12th, 1970, is claimed to be a "rate schedule" and has been so designated by FERC for both entities.

The project which has generated the sums now proposed to be allocated, involved the proposed Tyrone Nuclear Unit. It was a nuclear power plant to be built in Dunn County, Wisconsin, and would have served the entire NSP system. Originally, NSP was to own a portion of the plant, but a ruling of the Wisconsin Public Service Commission held that a non-Wisconsin corporation could not own any portion of the project. Hence, the entire ownership was transferred to NSP-W. Regulatory hearings on both state and federal levels proceeded seeking approval of the building of the plant. Ultimately, Wisconsin, through its Public Service Commission, denied a permit for the plant and the project was terminated, producing the losses which are now proposed to be allocated.

Subsequent to the termination, NSP and NSP-W in 1979 filed with FERC a proposed amendment to the Coordinating Agreement asking that the loss be shared according to the formula of the agreement. This would result in an increase in the costs paid by NSP for electricity used in Minnesota as previously noted. The proposed amendment was accepted for filing by FERC and hearings conducted. Both the Minnesota PUC and the North Dakota PUC intervened in the FERC proceedings, strenuously objecting to the amortization of any of the costs to either of their states. The federal administrative law judge (ALJ) in December of 1980 approved the amendment with certain minor modifications and subsequently the FERC final order approved the amendment extending the amortization period to ten years from the original five requested.

A proceeding was then commenced before the PUC by NSP to increase generally its rates to retail customers within the state of Minnesota. This matter was initially referred to Hearing Examiner DeLong, who recommended allowance of the full amount sought to be amortized under the Coordinating Agreement. The examiner concluded that the Coordinating Agreement and its amendments were a "rate schedule" within the *exclusive* jurisdiction of FERC. FERC had similarly found (See Opinion No. 134, Finding Amendment to Coordinating Agreement Just and Reasonable with Modification, App. 2 to NSP Brief). He further stated that the supremacy clause of the United States Constitution precluded the parties before the PUC from attacking the reasonableness of the rates prescribed by FERC. Noting that the PUC had already taken a position on the merits of the controversy before FERC and that "its express position thereon will be neither bolstered nor altered by further discussion of the facts and arguments", he felt that nothing was lost by his making recommendations on the merits of the issues.

As anticipated by the hearing examiner, the PUC by Order dated April 30th, 1981, denied recovery of the $10,928,000 of increased FERC rates due to the Tyrone amortization. The Commission felt that the Wisconsin PUC had acted in a parochial fashion in disregard for and in derogation of the integrated system concept in making its decision and that perhaps the decision reflected an anti-nuclear bias. The PUC also held that the Coordinating Agreement was not a valid wholesale interstate rate, but merely a method of allocating between the two entities the operational costs of an integrated utility. It felt, however, the crucial issue was one of authority to set retail utility

rates in Minnesota. Perhaps throwing down the gauntlet to the federal government, they asked "...who has the authority to set retail utility rates in Minnesota? NSP would reduce the Commission's role to that of a rubber stamp for an omnipotent FERC. The Company is able to make the leap of logic from interstate regulation to intrastate regulation. The Commission is not." (PUC Decision and Order, page 17). This appeal followed.

While many issues were raised in the briefs of the parties, it became clear at oral argument that the applicable law was not seriously disputed. In the abstract the parties also agree on what are the respective regulatory powers of FERC and the PUC. Clearly, federal regulation is proper when it concerns the transmission of electrical energy in interstate commerce and the sale of such energy at wholesale in interstate commerce, 16 U.S.C. Par. 824(a) (b). Cases such as *Federal Power Commission vs. Southern California Edison Company*, 376 U.S. 205, 84 S.Ct. 644, 11 L.Ed.2d 638 (1964) have confirmed that FERC and its predecessor, the Federal Power Commission, have exclusive authority to regulate interstate wholesale utility rates. However, there is a system of dual regulation, because individual states have specifically been left with the authority to regulate local retail rates to the ultimate consumer. The parties concede that, to the extent indicated, the federal government has occupied and preempted the field of rate regulation at the wholesale level. They question neither FERC's jurisdiction over wholesale rates nor the reasonableness of FERC's decision to allow the Tyrone losses to be reflected in the cost of services for NSP's wholesale customers. (Joint brief of respondents, p. 15). Likewise, if the rate set by FERC is a "rate for the

wholesale sale of power", respondents concede that all charges passed through the Coordinating Agreement would be binding on rates to *both* wholesale customers and retail customers of NSP. (See letter brief of respondents, June 8, 1982, p. 2). See also *Montana-Dakota Utilities vs. Northwestern Public Service Co.*, 341 U.S. 246 (1951); *Narragansett vs. Burke*, 381 A.2d 1359 (1977); *cert. den.* 435 U.S. 972 (1979) and *Northern States Power Company vs. Hagen, supra*. The effect of this federal preemption is obvious and was succinctly stated by the North Dakota Supreme Court:

> We concluded that for purposes of fixing intrastate rates, the Public Service Commission must treat NSP's filed interstate wholesale rates as a reasonable operating expense.
>
> We believe the doctrine of preemption requires the proper procedure to determine the reasonableness and prudence of the Tyrone loss as it relates to wholesale charges between NSP and NSP Wisconsin is to follow the remedies available in the proceeding before FERC. No valid reason has been presented that a determination of the reasonableness and prudence of the Tyrone loss cannot be adequately resolved through that procedure, which includes appeals to the proper court."

In its brief, respondent asserted that FERC has consistently recognized that state commissions have authority to determine the impact of abandonment losses upon *retail* rates. They leave to FERC only the power to regulate the amortization of losses to wholesale customers. They

cite several FERC opinions including *Virginia Electric Power Company, Louisiana Power and Light,* and *Philadelphia Electric Company* (Pgs. 26 and 27 of the Joint Brief of Respondents). At oral argument, it was conceded that those cases do not stand for the bald proposition that a state commission may ignore a validly established federal wholesale rate in setting retail rates. In any event, it appears that these cases are distinguishable upon their facts.

The critical issue, dispositive of this appeal, is whether the FERC Order on the Tyrone Petition constitutes a federally approved wholesale rate as between NSP and NSP-W. If the Coordinating Agreement and its amendments constitute such a rate, then there is little dispute but that the PUC *must,* under the law cited, accept the Tyrone cost allocation established by FERC. If it is not such a rate, then the Commission is free to decide for itself how the losses should be amortized, if at all.

The Commission found that the Coordinating Agreement was not a "wholesale rate". The scope of judicial review of that decision is set forth in Minn. Stat. 15.0425, which provides that a Court may:

> Reserve or modify the decision if the substantial rights of the petitioners may have been prejudiced because of the administrative findings, inferences, conclusion or decisions are: (a) in violation of Constitutional provisions; ... or (e) unsupported by substantial evidence in view of the entire record as submitted; ...

This scope of review has been limited by decisions of the Minnesota Supreme Court mandating that deference by

accorded decisions of administrative bodies, whole findings will not be disturbed on appeal unless unsupported by substantial evidence. See among others, *Northwestern Bell Telephone Company vs. State,* 216 N.W.2d 841 (1974) and *Hibbing Taconite Co. vs. Minnesota Public Service Commission,* 302 N.W.2d 5 (Minn. 1981).

While mindful of these admonitions, this Court believes, as did the North Dakota court, that the Order of the PUC asserting that it has jurisdiction over the rates previously set by FERC violates the supremacy clause of the Federal Constitution and the preemption doctrine prohibits such review. Further the PUC finding that the Coordinating Agreement with amendments is not a "wholesale rate" is not supported by substantial evidence or in accord with applicable law.

Arguing to sustain the PUC Order, respondents make several claims. First, they assert that the Coordinating Agreement is not a "wholesale rate" and merely operates as a contract to apportion investment costs and expenses between two affiliated companies. As a corollary to this first argument, they assert that because the entities, NSP and NSP-W, are so closely interrelated and are effectively operated as a single entity, the charges between them cannot be considered wholesale rates. Finally, they assert that because NSP-W does not and cannot sell power to NSP, the Coordinating Agreement cannot be considered a "wholesale rate", at least insofar as charges from NSP-W to NSP are concerned. This Court finds none of the arguments persuasive. Indeed the law clearly supports the arguments of the petitioner-appellant.

At the outset, it should be noted that in the proceedings before FERC, the Coordinating Agreement was treated

by all parties, including the respondents, as "rate" or "rate schedule". It was filed as a rate schedule (Decision of Administrative Law Judge [ALJ] P. 2). In denying a motion to dismiss filed by the Wisconsin Commission, FERC pointed out that the amendment to the Coordinating Agreement was a "rate change" upon which it had ordered a hearing (ALJ Decision, P. 3). Likewise, the full Commission in its Opinion and Order affirming the ALJ approved it as a "rate schedule change pursuant to § 205 of the Federal Power Act..." (FERC Opinion and Order, P. 9, Finding A).

It also appears that the use of coordinating agreements to determine "wholesale rates" has been recognized and in widespread use for a considerable period of time. Such a method has not been challenged even by the respondents until the present case. Indeed to the contrary, the Coordinating Agreement and the charges made between the companies under it have been accepted by the PUC in all of NSP's prior rate filings as establishing the reasonable cost for transactions between NSP and NSP-W.

As indicated earlier, the federal regulatory scheme clearly contemplates that the interstate transfer of electrical power at wholesale will be subject to regulation by FERC. Sections 205(c) and (d) of the Federal Power Act note that rate schedules and changes in rate schedules must be filed with FERC. Other sections allow the Commission to review the filing to determine if the rates are reasonable. Regulations of the Commission use the term "rate schedule" and note that it has three components: A statement of the electrical service; the rates; and charges and classifications, practices, rules, regulations or contracts. It contains some components in addition to the rate, but

is not legally different. It is specifically noted that such a rate schedule may take the form of a contractural document (FERC Regulations, Section 35.2(b)).

FERC clearly considers these coordinating agreements to be rates and subject to their jurisdiction. In accepting the amendment to the Agreement for filing, they noted that increased payments reflecting the Tyrone amortization "will be reflected as purchase power expense in any NSP cost-of-service". (Order Accepting for Filing [etc.], October 22, 1979, P. 2).

Section 201 of the Federal Power Act speaks of the transmission of electrical energy in interstate commerce. Paragraph (c) of that section defines when electricity shall be held to be transmitted in interstate commerce, Section (d) defines wholesale sale and Section (e) defines a Public Utility as "any person who owns or operates facilities". Clearly NSP and NSP-W are separate and independent "persons" and separate "public utilities" under the Act. They have been found to be such by FERC, NSP in 1955 and NSP-W in 1957. The fact that one is a subsidiary of the other is clearly not dispositive. Indeed *Narragansett, supra,* involved a similar relationship and also referred to the price or rate established by a "contract". (381 A.2d at 1363.)

Under the federal law, these companies have thus been recognized as separate "public utilities" and have been compelled to transact business under federally regulated wholesale rates. It would be illegal for them to interconnect or exchange electricity, except under the regulation of FERC, through a Coordinating Agreement or some other form of regulated rate. Clearly energy in the NSP-NSP-W system flows across state lines at the wholesale level. Both com-

panies own generating facilities and the flow of electricity *could* go either direction at any point in time. It follows that the interchange and exchange of power is necessarily under FERC jurisdiction. This Court believes that the fact that power *may* only flow in one direction from Minnesota to Wisconsin, is irrelevant. Both the Act itself and the regulations under it speak generally of the transmission as well as the sale of electrical energy and refer to interchange and exchange of power when referring to the type of matters subject to FERC regulation. Nowhere does there appear any requirement that the energy flow in any particular direction.

At all stages of this proceeding and indeed in its Order, the PUC advanced the argument that the Wisconsin Public Service Commission acted in a parochial fashion in disregard and in derogation of the integrated-system concept and perhaps with an antinuclear bias. Both the administrative law judge and the hearing examiner rejected this argument. The ALJ felt that the reasons for rejection by the Wisconsin PSC were relatively unimportant and that the project was planned and carried forward in a prudent manner to meet the combined needs of the entire NSP integrated system. He also found that the utilities were not imprudent in cancelling the project. He felt that even if the Wisconsin Commission acted incorrectly, its sins, if any, should not be "visited entirely on NSP-Wisconsin" (ALJ Opinion P. 8). The Minnesota Hearing Examiner, Mr. DeLong, deemed the parochial argument not relevant noting that intervenors who take this position are rather candidly arguing for the right of the PUC to prevail with a parochial decision of its own. This Court agrees with the conclusions of both individuals.

The PUC is not left without a remedy in situations such as this. The proposed amortization may be and indeed in this case was challenged in a contested proceeding before FERC and the appeal of the FERC decision by respondents is now before the Eighth Circuit Federal Court of Appeals. The challenge before FERC could have included an attack on the validity of the Coordinating Agreement itself and FERC's assumption of jurisdiction over the abandonment losses (matters apparently not pressed by the respondents).

CONCLUSION

There is little dispute on the applicable law. All of the legal decisions cited support appellant's position. Clearly the regulation of interstate rates has been vested in FERC to avoid conflicting political considerations and competing views of states which would have to be resolved on an individual basis. To allow these "just and reasonable rates" determined by FERC to be collaterally attacked in subsequent proceedings before state commissions would frustrate the very reason that FERC and its jurisdiction over interstate transmission and sales of electrical energy was established in the first place. Congressional intent to place the determination in a single body, removed from state parochialism, would be defeated. The North Dakota Supreme Court reached the same conclusion.

> "The PSC has no direct jurisdiction over interstate wholesale rates and we believe it would undermine the supremacy clause and the preemption doctrine for the PSC to indirectly assert jurisdiction over the wholesale rate by investigating the reasonableness

> of underlying costs in a proceeding involving retail rates. Furthermore, we believe it would frustrate the purpose of Congress in establishing reasonable wholesale rates if the reasonableness of these rates as an operating expense were inquired into by and made subject to the North Dakota PSC in establishing reasonable retail rates. If this were permitted, the efforts of FERC would be reviewable by the PSC, which was not contemplated by the Congressional Act. NSP vs. Hagen, supra, at P. 38.

Having concluded that the Coordinating Agreement is a wholesale rate subject to FERC jurisdiction, it follows that respondents may not choose to ignore it and/or the FERC orders. They remain free to pursue and challenge all aspects of the matter before FERC and in the federal courts. However, in accordance with the views expressed above, the Order of the PUC must be reversed.

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Roger L. Hanson	Chairman
Leo G. Adams	Commissioner
Terry Hoffman	Commissioner
Lillian W. Lazenberry	Commissioner
Juanita R. Satterlee	Commissioner

In the Matter of the Petition of Northern States Power Company, Minneapolis, Minnesota, for Authority to Change its Schedule of Electric Rates for Retail Customers Within the State of Minnesota.

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER

DOCKET NO. E-002/GR-80-316

PROCEDURAL HISTORY

This proceeding was initiated after Northern States Power Company (MSP or the Company) filed a Notice of Change in Rates with the Minnesota Public Service Commission, now the Minnesota Public Utilities Commission (the Commission) on May 1, 1980. The notice was filed pursuant to M.S. §216B.16, which requires 90 days notice before rates may be changed. NSP proposed an increase in revenues of $77,530,000 or 12.66%. The proposed schedule of rates would be effective on July 30, 1980, the expiration of the 90 day notice period.

By its Order, dated May 14, 1980, the Commission accepted the Company's petition, suspended the proposed rate schedule, and ordered a hearing in the matter to determine whether the rates were unjust or unreasonable.

The Commission requested a Hearing Examiner from the Office of Administrative Hearings on May 23, 1980, and Examiner Richard DeLong was assigned. The Examiner held a Prehearing Conference on June 16, 1980 which set dates for evidentiary and public hearings and set July 14, 1980, as the last date for intervention.

On June 12, 1980, the Commission issued a Notice and Order for Hearing which directed NSP to provide addional information for the record on advertising, test year sales, long range forecasting, and seasonal rate differentials.

The following were made parties to this proceeding:

1. Minnesota Department of Public Service (DPS)
2. Minnesota Office of Consumer Services (OCS)

3. The City of Saint Paul (St. Paul)
4. The City of Minneapolis
5. Minnesota Energy Agency (MEA)
6. Suburban Rate Authority (SRA)
7. Union Carbide Corporation (Union Carbide)
8. St. Paul Area Chamber of Commerce (Chamber)
9. Minnesota Public Interest Research Group (MPIRG)
10. St. Regis Paper Company (St. Regis)
11. United Handicapped Federation (UHF)
12. Minnesota Citizen Action, Inc. (MCA)
13. Minnesota Senior Federation (Seniors)
14. Liberty Diversified Industries, Inc., Liberty Carton Company, and Shamrock Industries, Inc. (Liberty)
15. Minnesota Department of Administration (DOA)

Twenty days of evidentiary hearings were held in St. Paul, Minnesota. The following appearances were made at the hearings:

Samuel L. Hanson, Attorney at Law, 2452 IDS Center, Minneapolis, Minnesota 55402, and Gene Sommers and David Lawrence, Attorneys at Law, Fifth Floor, 414 Nicollet Mall, Minneapolis, Minnesota, appeared on behalf of NSP.

The Commission accepts the DPS adjustment for revised depreciation rates but as calculated by the Company in Schedule 2 attached to its exception to the Examiner's Report. The Commission finds that test year net operating income should be increased by $239,000 because of this adjustment.

C. Pollution control property tax contingency.

As previously discussed under rate base, the Company has applied to the Minnesota Pollution Control Agency and the State Department of Revenue for a property tax exemption for certain nuclear plant pollution control facilities. Pending approval, the Company included in test year property tax expense the amount of $898,000 as a provision for the "Pollution Control Contingency Fund". The DPS stated that at the present time no ruling has been given by either department, nor have any taxes been paid. The PDS deducted the $898,000 from test year operating expenses because the tax liability is speculative.

In rebuttal testimony the Company accepted this DPS adjustment with the provision that the Commission include this amount in test year operating expense in the event that the Company receives an unfavorable ruling on its application for property tax exemption.

The Examiner found that test year operating expenses should be reduced by $898,000 by reason of removing that amount from its property tax budget provision for the pollution control contingency fund.

Again, if property tax relating to generating plants is reduced, there should be a resultant decrease in other operating revenues because of lower revenues coming from NSP-Wisconsin through the Coordinating Agreement. The Company's corrections of the Examiner's mathematical errors in its exceptions to the Examiner Report reflects a reduction in other operating revenue of $124,000 associated with this adjustment.

The Commission accepts the DPS adjustment but as calculated by the Company in its exceptions to the Examiner's Report. The Commission finds that test year net operating

income should be increased in the amount of $402,000 because of this test year reduction in property tax expense.

D. Tyrone amortization.

1. Background.

NSP, the Minnesota corporation, has a wholly owned subsidiary, NSP-Wisconsin (NSP-W). NSP-W was created because Wisconsin law requires utility business in that state be conducted by domestic corporations. The two companies operate an integrated power supply system, with NSP providing service in Minnesota, North Dakota and South Dakota, and NSP-W providing service in Wisconsin.

In 1970, the two companies filed a Coordinating Agreement with the Federal Energy Regulatory Commission (then the Federal Power Commission) (FERC). That agreement was designed to apportion joint costs of generating facilities between the two corporate entities. Costs of production, transmission, and related operating and maintenance are shared based upon predetermined ration set so that the costs assumed by each company reflect the demand and energy requirements each company imposes on the integrated system. Fixed costs are split between the companies based upon a rolling average ratio developed from coincident summer and winter peak demands from the preceeding four years plus one projected year. The relevant fixed cost ratio is 87% to NSP and 13% to NSP-W.

In the mid 1970's NSP began planning a nuclear fueled electric generating facility near Durand, Wisconsin, which became known as the Tyrone Energy Park, or just the Tyrone plant. Ownership of the plant was to be shared

among NSP, NSP-W, and a group of other utilities. NSP transferred its interest to NSP-W in 1978 to comply with a Wisconsin Public Service Commission (WPSC) ruling that a foreign corporation could not have an ownership interest in a Wisconsin sited facility.

The owners of the Tyrone plant secured a favorable Advance Plan decision from the WPSC and began securing the necessary federal permits. On March 6, 1979, however, the WPSC denied a Certificate of Public Convenience and Necessity for Tyrone, and the co-owners subsequently decided to abandon the uncompleted project.

On August 24, 1979, NSP and NSP-W filed an amendment to the 1970 coordinating agreement with the FERC, providing for the apportionment of NSP-W's loss on the Tyrone plant to NSP based upon the 87%-13% ratio for sharing fixed charges for existing generating facilities.

2. NSP.

NSP's filed case herein contains an expense in the amount of $10,928,000 representing one year of a five-year amortization of the Tyrone Plant abandonment loss. The expense increased the monthly charges billed to NSP by NSP-W under the coordinating agreement (with the proposed amendment).

NSP argued that the Commission is obligated to allow the monthly charges from NSP-W as a reasonable operating expense to NSP, because federal regulation has preempted the Commission's authority to investigate the reasonableness of interstate rate or any of its cost components. In support of that argument, the Company asserted that the Coordinating Agreement is a valid wholesale interstate rate, governing the compensation for exchange of electricity be-

tween two distinct utilities across a state line, accepted and identified by the FERC as an interstate rate.

Further, NSP stated that the FERC has been given exclusive jurisdiction over interstate ratemaking by the Natural Gas and Federal Power Acts, leaving to the states exclusive authority over intrastate rates for services rendered to ultimate consumers. The Company cited the case of *Narragansett Electric Company v. Burke*, 381 A.2d 1358 (R.I. 1977) as support for its contention that a state regulatory agency cannot question the reasonableness of an interstate wholesale rate by the FERC. NSP argued that a rate filed and charged under bond was entitled to the same deference as a finally-approved rate.

Finally, the Company described all intervenor challenges to the proposed amortization as collateral attacks, inappropriately arguing issues of the FERC case rather than addressing issues before the Commission.

3. DPS.

The DPS removed the Tyrone abandonment loss expense as one of its expense adjustments, arguing that the WPSC improperly denied the need for the Tyrone facility by rejecting the intergrated system concept in favor of a western Wisconsin need test, and by basing its decision on an anti-nuclear bias. The DPS noted that the Commission was not represented before the WPSC, and that the only Minnesota intervenor, the MEA, testified in support of the need for Tyrone. Allowing the results of such an improper decision to fall upon the heads of Minnesota ratepayers would be unjust.

The DPS opposed NSP's contention that the FERC has preempted a Commission decision on the impact the Ty-

rone abandonment would have on Minnesota retail rates. The DPS argued that the Coordinating Agreement is not a wholesale rate schedule, and that the FERC could only make a binding decision as to NSP's wholesale customers. The DPS stated that the Commission has sole jurisdiction to determine whether a portion of the Tyrone loss may be reflected in Minnesota retail rates, regardless of whether the FERC has the power to decide the apportionment of the loss to the two utilities.

4. Other parties.

OCS contended that Minnesota ratepayers should not pay for the Tyrone loss, because Minnesota had no voice in the WPSC decision, and because the abandonment was not based upon valid integrated system operating forecasts. If any portion of the loss was to be assumed by Minnesota ratepayers, OCS urged the loss be amortized over the life of the coal-fired Tyrone replacement facility rather than the five-year period advanced by NSP.

MPIRG argued that the Tyrone loss should be borne by NSP's stockholders, who provided the capital, took the risk on investing and controlled the management of the company. To shift the loss now to ratepayers would be unfair.

MEA generally opposed passing the costs of Tyrone on to ratepayers. SRA urged that NSP be allowed to recover the Tyrone loss over a 7 to 10 year period.

5. Examiner's recommendation.

The Examiner deemed it unnecessary to make findings and conclusions on this issue because, in his opinion, sole jurisdiction over the matter lies with the FERC. He noted

the Commission must be intimately familiar with the facts and arguments concerning the Tyrone project, in light of the considerable controversy it has generated and based upon the Commission's intervention before the FERC in the matter.

6. Commission conclusion.

The Examiner is correct that the Commission is quite familiar with the circumstances surrounding the planning, cancellation, and abandonment of the Tyrone facility. General public awareness has been high. The media have devoted considerable attention to the matter. The Commission intervened before the FERC in opposition to the NSP companies' proposed amendment to the Coordinating Agreement. While taking administrative notice of the general, public information and the record of the proceedings before the FERC, the Commission places primary reliance for its discussion on the record herein, which has recapitulated most of what has gone before.

Nothing in this record has persuaded the Commission that it is wrong in its long-held belief that the WPSC acted in a parochial fashion, in disregard for and in derogation of the integrated-system concept when it denied the need certificate for Tyrone on solely western Wisconsin growth projections. That decision was made on the wrong grounds, even without consideration of the anti-nuclear bias which some parties have attributed to the WPSC.

Likewise, the Commisison finds no persuasive support herein for the proposition that the Coordinating Agreement is a valid wholesale interstate rate. The ratios sought to be used to transfer the Tyrone loss to Minnesota are taken from a cost-sharing formula under the Agreement

that relates cost responsibility to historic and projected future peak demand. This is a far cry from a rate schedule between utilities that bases charges on energy and capacity actually consumed over the most recent month. The fact that the FERC accepted the filing of the original Agreement and the amendment is not dispositive of the question of what those agreements really are. The Commission finds ample evidence on this record to classify the Agreement as merely a method of allocating among jurisdictions the operational costs of an integrated utility, planned and run as a single entity, not as two companies. To assert there was arms-length bargaining between NSP and NSP-W about the division of the expenses of building and running a multi-state system would fly in the face of the testimony herein.

But these facts skirt the crucial issue; who has the authority to set retail utility rates in Minnesota? NSP would reduce the Commission's role to that of a rubber stamp for a omnipotent FERC. The Company is able to make the leap of logic from interstate regulation to intrastate regulation. The Commission is not.

Congress has indeed given the FERC authority over wholesale rates charged in interstate commerce, but no interstate wholesale rate is proposed to be set in this proceeding. The purpose of this rate hearing is to set intrastate retail rates. The transaction being examined is between an intrastate utility and its ultimate consumers. Here the Federal system still must recognize the sovereign right of the state. No Federal preemption has stripped state regulatory bodies of the authority to determine what various retail customers will pay for their electricity.

Even the most expansive reading of the FERC's juris-

diction could only conclude that the FERC can apportion the Tyrone loss between the two corporate entities, NSP and NSP-W. Even if the FERC can go that far, it must stop at that point, and allow the states to carry the process further. NSP quoted the FERC's Administrative Law Judge, but ignored his clear acknowledgment of his agency's limitations:

> ...if some 85% of the NSP cancellation costs are allocated to NSP-Minnesota pursuant to the Coordinating Agreement, as proposed by the two NSP Companies, then these costs *may* become a part of NSP-Minnesota's rather than NSP-Wisconsin's, cost of service, and in turn *may* be passed on to the customers of NSP-Minnesota....

Initial

Order at 4. (Emphasis added.

The ALJ recognized that regardless of what the FERC might do, it would remain a Commission decision as to how to recognize that decision in retail rates.

The Commission finds that cancellation of the Tyrone project did not result from an application of the unified-system concept underlying the Coordinating Agreement's distribution of costs. The Agreement is thus not an appropriate benchmark for division of any cancellation costs.

The Commission further finds the cancellation was of no benefit to Minnesota ratepayers, and finds that those ratepayers and their needs were not an element of the cancellation decision.

The Commission concludes that the expenses of the Tyrone abandonment are not a reasonable expense to be included in Minnesota retail rates, no matter in what form those expenses may be presented. The Commission con-

cludes it has the obligation to protect all Minnesota ratepayers from the effects of the Tyrone loss. The owners of the two NSP companies are able to direct management in the selection of types, sizes, and location of the facilities in which those owners have chosen to invest. Those owners control their companies and assume the risks of ownership by investing. Minnesota ratepayers cannot be asked to insulate the owners from all financial risk. The amortization of the Tyrone loss as requested by NSP is rejected, and the $10,920,000 will be removed from test year expenses.

E. Sherco 3.

Since the Commission has accepted the DPS removal of Sherco 3 CWIP from rate base, it also accepts the DPS adjustment to the test year operating income statement which results from that rate base disallowance. Operating revenue received through the Coordinating Agreement should be reduced by $96,000. The rate base reduction reduces the interest expense that is assigned to the Minnesota jurisdiction and increases income taxes. Elimination of Sherco 3 from rate base also requires the elimination of the offsetting AFDC associated with Sherco 3 CWIP. The Commission finds that the appropriate adjustment to the test year income statement results in a reduction of net operating income in the amount of $1,843,000 and a reduction of test year AFDC in the amount of $7,959,000 for a reduction in the total available for return amounting to $9,802,000.

F. Sherco 4 Amortization.

Included in the Company's test year operating expenses are $800,000 of amortization costs relating to the aband-

onment of a previously planned generating facility in Sherburne County, Minnesota, known as Sherco 4. The $800,-000 represents the jurisdictional share of the last seven months of a three year amortization plan which began in March of 1978. The DPS eliminated Sherco 4 amortization from test year operating expense, claiming that the decision to proceed with the plant, to delay and later to abandon the project were management decisions based on the Company's changing load forecasts. The DPS recommended that the stockholders, not the ratepayers.

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Roger L. Hanson	Chairman
Leo G. Adams	Commissioner
Terry Hoffman	Commisisoner
Juanita R. Satterlee	Commissioner
Lillian Warren-Lazenberry	Commissioner

In the Matter of the Petition of Northern States Power Company, Minneapolis, Minnesota, for Authority to Change its Schedule of Electric Rates for Retail Customers within the State of Minnesota.

DOCKET NO. E-002/GR-80-316

ORDER UPON RECONSIDERATION

On April 30, 1981, the Minnesota Public Utilities Commission (the Commission) issued its Findings of Fact,

Conclusions of Law, and Order in the above-captioned matter. Petitions for rehearing or reconsideration of that Order were received from Northern States Power Company (NSP), the Office of Consumer Services (OCS), the St. Paul Area Chamber of Commerce (Chamber), Minnesota Public Interest Research Group (MPIRG), and the United Handicapped Federation (UHF). Replies to those petitions were received from NSP, OCS, MPIRG, the Department of Public Service and the City of St. Paul. In addition, the Minnesota Senior Federation (the Seniors) filed an Accounting of Expenses.

NSP claimed Commission error in setting a rate of return on common equity; denying the Tyrone abandonment loss; denying working capital requirements for delay in recovery of depreciation, deferred taxes, and nuclear fuel amortization, as well as preliminary survey and investigation charges and employee working funds; and for removing Sherco III from construction work in progress.

The OCS urged reconsideration of the Commission's allocation of revenues to customer classes. The Chamber claimed error in the Commission's using of the stratified cost of service study, setting the customer service charge, eliminating declining block rates for large general service customers, adopting NSP's proposal regarding the 90% power factor, and maintaining the rachet for interruptible customers.

MPIRG asked for rehearing and reconsideration on the issues of executive salary expenses, billing expenses, "Ask NSP" expenses, nuclear advertising, and the service order fee for residential customers. UHF requested reconsideration of the Commission's decisions requiring further development of the medically necessary usage rate, restricting

the time allowed for Oral Argument, and failing to reimburse UHF for its costs of intervention.

The Seniors filed a more detailed accounting of their expenses of participation in the case.

Upon a review of the petitions, the Commission finds that no persuasive grounds for reconsideration or rehearing have been presented by the parties. The arguments presented were within the scope of arguments made before the Commission's initial Order. Accordingly, the Commission concludes that the requests for reconsideration or rehearing must be denied.

Notwithstanding the conclusion above, the Commission finds that two points of clarification should be made in the initial Order. As NSP noted, the Commission's inclusion of the phrase, "at that time" at line 21, page 6 in the decision of Sherco III, created confusion. That phrase will be removed. Further, the Commission agrees with NSP that the phrase, "spot dividend yield" at line 32, page 32, in the discussion of rate of return on common equity, was a misstatement. Those words will be replaced with the words, "bond yield."

The other issue remaining is that of intervenor compensation. The Seniors, UHF, and Minnesota Citizens Action each requested reimbursement of their expenses of participation in the rate case. The Commission has scrutinized the itemization of expenses submitted by each intervenor, and has reviewed the participation of each of the intervenors.

The Commission finds that each intervenor participated actively in portions of the case and presented testimony bearing on Commission decisions. In *Minnesota Power & Light Company*, Docket No. E-015/GR-78-514 (April 9,

1979), at 36, the Commission found the Senior Citizen Coalition of Northeastern Minnesota's participation had been helpful and illuminating, that the Commission wished to insure the continued participation of the Coalition, and recognized the Coalition's limited resources. The Commission awarded partial reimbursement of the Coalition's expense. In *Minnesota Power and Light Company*, Docket No. E-015/GR-80-76 (Jan. 30, 1981), at 50, the Commission found the Coalition had contributed substantially to two Commission decisions, and found that participation would have been a hardship without reimbursement. Full reimbursement was ordered.

The Commission acknowledges that it has not yet established firm criteria for awarding compensation. The Commission finds that the intervenors herein have made a showing sufficient to support reimbursement based on the standards enumerated in the earlier case, and concludes that awarding compensation here is appropriate.

Lack of a predictable policy in this area poses problems for potential intervenors and the Commission. In particular, the Commission is concerned about the costs of funding intervenors which must ultimately be borne by a utility's ratepayers. To provide guidance, the Commission hereby announces it intends to review all future requests for reimbursement by determining whether the intervenor made a substantial contribution to the Commission's adoption of a position advocated by the party, whether the intervenor made a contribution to the case different from the other parties, and whether the intervenor will be able to continue operating without the requested award.

ORDER

1. Within 15 days of the service date of this Order, Northern States Power Company shall pay to the Minnesota Senior Federation the sum of $12,497,22, to the United Handicapped Federation the sum of $7,665.00, and to Minnesota Citizen Action the sum of $3,340.00.

2. The Commission's April 30, 1981 Order is corrected in the two places noted herein.

3. The petitions for rehearing and reconsideration are in all other respects denied.

BY ORDER OF THE COMMISSION

/s/ Randall D. Young
Executive Secretary

SERVICE DATE: June 17, 1981.
(SEAL)
RDY:vm

COORDINATION AGREEMENT

Between

NORTHERN STATES POWER COMPANY (Minnesota)

and

NORTHERN STATES POWER COMPANY (Wisconsin)

THIS AGREEMENT, made this 12th day of October, 1970, by and between NORTHERN STATES POWER COMPANY, a Wisconsin corporation hereinafter referred to as the "Wisconsin Company"; and NORTHERN STATES POWER COMPANY, a Minnesota corporation, hereinafter referred to as the "Minnesota Company",

WITNESSETH

0.01 WHEREAS, the parties to this Agreement, hereinafter called "Parties" collectively, or "Party" singularly, are the owners and operators of electric generation and transmission facilities and are engaged in the business of providing electric power and energy; and

0.02 WHEREAS, the Wisconsin Company is a wholly owned subsidiary of the Minnesota Company; and

0.03 WHEREAS, the systems of the Parties are interconnected directly and indirectly and are operating in synchronism; and

0.04 WHEREAS, the Parties desire to coordinate the development and operation of their respective generation and transmission facilities and the purchase and sale of electric power and energy to avail themselves of economical and effective supply of power and energy; and

0.05 WHEREAS, the Parties desire to utilize all generation and transmission facilities of the Parties to effect economical and reliable operation in supplying the electrical loads of the Parties; and

0.06 WHEREAS, the Parties desire to establish the bases of sharing the costs and benefits of such coordination;

NOW THEREFORE, the Parties mutually understand and agree as follows:

ARTICLE I

ELECTRIC POWER AND ENERGY SUPPLY

1.01 *Availability and Interchange of Power and Energy.* The availability of power and energy shall be coordinated and interchanged by the Parties as may be necessary to provide an adequate and reliable supply of power and energy for the requirements of the Parties on a mutually economic basis.

1.02 *Plans and Supporting Studies.* The Parties shall conduct joint studies and planning to determine the generation and transmission facilities which are required to provide an adequate and reliable supply of electric power and energy for the requirements of the Parties.

1.03 *Emergency Service from a Third Power.* In the event of an emegency on a Party's system the other Party will procure emergency service from other systems which may be available. The Party procuring such service shall be the sole judge of its ability to supply emergency service.

ARTICLE II

DEFINITIONS

2.01 *System Coincidental Maximum Demand* is the maximum net demand that occurs on the combined systems of both Parties.

2.02 *Wisconsin Company Coincidental Maximum Demand* is that part of the System Coincidental Maximum Demand that occurs simultaneously on the Wisconsin Company system.

2.03 *Minnesota Company Coincidental Maximum Demand* is that part of the System Coincidental Maximum Demand that occurs simultaneously on the Minnesota Company system.

2.04 *Participation Ratios* are the two ratios established in Exhibit "A" for allocating fixed costs to the appropriate Party.

2.05 Extra High Voltage Transmission (EHV) are those transmission facilities owned by the Parties having a voltage rating of 230 KV or more placed in service subsequent to January 1, 1966.

ARTICLE III

OPERATING COMMITTEE

3.01 *Operating Committee.* In order that the advantages intended to be derived hereunder may be realized, the Parties shall establish a committee to be known as the Operating Committee to coordinate the operations between the systems. Each of the Parties shall designate, in writing, the two persons who are to act as its representatives on said committee.

The Operating Committee shall be responsible for the following:

a. Determining the Participation Ratios for calculating compensation. (Such determination shall be made in January of each year)

b. Coordinating the annual planning and design of the installation of generation and EHV transmission facilities for the ensuing 10 year period.

c. Coordinating the operation and maintenance of generation and EHV transmission facilities of the Parties.

d. Establishing procedures for the calculation of the amounts of power and energy exchanged between the Parties.

e. Establishing procedures covering transmission losses associated with transactions between either Party and a third party which may result in an abnormal increase in transmission losses on the system of the other Party hereto.

f. Such other matters which are necessary in order to carry out the purposes of this Agreement.

ARTICLE IV

OPERATION AND MAINTENANCE

4.01 *Operation.* The systems of the Parties shall be operated in continuous synchronism. If the synchronous operation of the systems becomes interrupted because of reasons beyond the control of either Party or because of scheduled construction or maintenance, the Parties shall cooperate

to remove the cause of such interruption as soon as practicable and restore such facilities to normal operating condition.

4.02 *Service Conditions.* It is intended that neither Party shall be obligated to deliver reactive power to the other Party or to receive reactive power from the other Party when to do so may introduce objectionable operating conditions on the system of either Party. It is recognized that in order to assure adequate service and economical use of the facilities of both systems it may be necessary from time to time to establish operating procedures for carrying reactive power loads by either system for the other.

4.03 *Character of Service.* Power and energy shall be delivered as three-phase alternating current, at a frequency of approximately 60 Hz with such variations from nominal voltages as may be mutually established from time to time.

4.04 *Continuity of Delivery.* Power and energy delivered under this Agreement shall be furnished continuously except for interruptions or curtailments in service caused by an uncontrollable force, or by operation of devices installed for system protection, or by the necessary installation, maintenance, repair, and replacement of facilities. Such interruptions or reductions in service shall not constitute a breach of this Agreement, and neither Party shall be liable to the other for damages resulting therefrom. Except in case of emergency, each Party shall give reasonable advance notice of temporary interruptions or curtailments in service necessary for such installations, maintenance, repair and replacement of facilities, and shall attempt to schedule such interruption or curtailments as convenient for both Parties.

4.05 *Recognition of Flow of Power and Energy.* It is recognized by the Parties that their respective electric systems are and will be directly or indirectly interconnected with electric systems owned or operated by others, that the flow of power and energy between the systems of the Parties will in part be controlled by the physical and electrical characteristics of the facilities involved and the manner in which they are operated, and that part of the power and energy being delivered under this Agreement may flow through such other systems rather than through the facilities of the Parties.

Each Party will at all times cooperate with other interconnected systems in establishing arrangements which may be necessary to relieve any hardship on other systems caused by energy flows from deliveries hereunder.

4.06 *Correction of Trouble.* In the event that the interconnected operation of the systems herein contemplated results in trouble on either Party's system including, but not limited to, interruptions, grounds, communication interference, unreasonable surges, or objectionable voltage fluctuations, where such trouble is caused by the method of operation or the facilities employed by the other Party, its customers, or third party suppliers connected to its lines, such trouble shall be corrected by the Party on or through whose system it originates within a reasonable time after written notice thereof. If the Parties cannot resolve a question relative to such trouble, such question may be submitted to arbitration by either Party.

ARTICLE V

INTERCONNECTION OF SYSTEMS

5.01 *Transmission Facilities.* The Parties will maintain adequate interconnections between their respective systems which will permit interchange of electric power and energy pursuant to this Agreement.

5.02 *Associated System Facilities.* Each Party will provide in its system facilities for such telemetering, load control, communication, and relay protection as is necessary for the proper operation of the interconnected systetms.

ARTICLE VI

METERING

6.01 *Metering.* Suitable metering equipment shall be installed for determining the flow of power and energy between the Parties. The ownership of and responsibility for metering equipment will be determined by the Parties. Either Party may at any time install and maintain duplicate meters at its own expense.

6.02 *Meter Readings.* Each Party will read its meters at times to be agreed upon and promptly forward such registrations to the other Party.

6.03 *Meter Tests, Accuracy and Adjustments.* Each meter shall be tested periodically and maintained in an accurate condition by the Party owning the meter in accordance with rules prescribed by regulatory bodies having jurisdiction thereof. Adjustment of any meter readings for meter error shall not extend beyond 60 days previous to the day on which inaccuracy is discovered. Should any

metering equipment at any time fail to register, or should the registration thereof be so erratic as to be meaningless, the quantities of power and energy delivered shall be determined from the best information available.

ARTICLE VII

COMPENSATION

7.01 *Compensation General Principle.* In calculating the compensation to be paid by one Party to the other Party for electric power and energy from the generation and EHV transmission facilities of the other Party, the objective is to compensate the Party owning such generation and transmission facilities on an equitable basis for its costs including fixed charges, and operating and maintenance expenses.

7.02 *Sharing of Fixed Charges for Generation Facilities.* The annual fixed charges on generation facilities (net book basis) will be shared on the following basis:

a. The Minnesota Company will pay the Wisconsin Company an amount determined by multiplying the Wisconsin Company's annual fixed charges by the Participation Ratio for the Minnesota Company.

b. The Wisconsin Company will pay the Minnesota Company an amount determined by multiplying the Minnesota Company's annual fixed charges by the Participation Ratio for the Wisconsin Company.

c. Payments for the current year will be made monthly and each monthly payment shall be one-twelfth of the estimated annual amount. Interim adjust-

ments within the current year will be made when deemed necessary.

When the actual annual fixed charges are available, the annual payments shall be redetermined and the total annual payment by each Party to the other shall be adjusted to reflect the actual annual fixed charges.

7.03 *Sharing of Fixed Operating and Maintenance Costs for Generation Facilities and Power Transactions.* The fixed operating and maintenance costs for generation facilities and power transactions will be shared on the following basis:

a. The Minnesota Company will pay the Wisconsin Company an amount determined by multiplying the Wisconsin Company's monthly fixed operating and maintenance costs by the Participation Ratio for the Minnesota Company.

b. The Wisconsin Company will pay the Minnesota Company an amount determined by multiplying the Minnesota Company's monthly fixed operating and maintenance costs by the Participation Ratio for the Wisconsin Company.

c. The fixed operating and maintenance costs shall include the following:

    (1) Fixed operating and maintenance costs for generation facilities

    (2) Demand charge for purchased power

(3) Credit for demand portion of power sales which are not required to satisfy the System Coincidental Maximum Demand.

Fixed costs payments for the current month will be based on fixed costs for the previous month.

7.04 *Sharing of Variable Operating and Maintenance Costs for Generation Facilities and Power Transactions.* The variable operating and maintenance costs for generation facilities and power transactions will be shared on the following basis:

a. The Minnesota Company will pay the Wisconsin Company an amount determined by multiplying the Wisconsin Company's monthly variable operating and maintenance costs by the ratio of the Minnesota Company's monthly Kwh requirements to the total monthly Kwh requirements of the Parties.

b. The Wisconsin Company will pay the Minnesota Company an amount determined by multiplying the Minnesota Company's monthly variable operating and maintenance costs by the ratio of the Wisconsin Company's monthly Kwh requirements to the total monthly Kwh requirements of the Parties.

c. The variable operating and maintenance costs shall include the following:

(1) Fuel expense

(2) Variable operating and maintenance costs for generation facilities

(3) Costs of purchased energy

(4) Credit for energy sales which are not required to satisfy the System Coincidental Maximum Demand.

Variable costs payments for the current month will be based on variable costs for the previous month.

7.05 *Sharing of Fixed Charges for EHV Transmission Facilities.* The annual fixed charges for EHV transmission facilities (net book basis) will be shared on the following basis:

a. The Minnesota Company will pay the Wisconsin Company an amount determined by multiplying the Wisconsin Company's annual fixed charges by the Participation Ratio for the Minnesota Company.

b. The Wisconsin Company will pay the Minnesota Company an amount determined by multiplying the Minnesota Company's annual fixed charges by the Participation Ratio for the Wisconsin Company.

c. Payments for the current year will be made monthly and each monthly payment shall be one-twelfth of the estimated annual amount. Interim adjustments within the current year will be made when deemed necessary.

   When the actual annual fixed charges are available, the annual payments shall be redetermined and the total annual payment by each Party to the other shall be adjusted to reflect the actual annual fixed charges.

7.06 *Sharing of Operating and Maintenance Costs for EHV Transmission Facilities.* The operating and maintenance costs for EHV transmission facilities will be shared on the following basis:

a. The Minnesota Company will pay the Wisconsin Company an amount determined by multiplying the Wisconsin Company's monthly operating and maintenance costs by the Participation Ratio for the Minnesota Company.

b. The Wisconsin Company will pay the Minnesota Company an amount determined by multiplying the Minnesota Company's monthly operating and maintenance costs by the Participation Ratio for the Wisconsin Company.

Payments for operating and maintenance costs in the current month will be based on operating and maintenance costs for the previous month.

7.07 *Statements.* As promptly as practicable after the first day of each calendar month, the Parties shall cause to be prepared a statement setting forth the transactions between the Parties during the preceding month in such detail and with such segregation as may be needed for operating records or for settlements under the provisions of this Agreement.

7.08 *Method of Settlement.* Accounts between the Parties shall be settled monthly as hereinafter provided. Monthly bills will be prepared for amounts owed by one Party to the other for the other Party's share of the assignable costs. A written billing statement shall be pre-

pared setting forth in detail the charges and credits to each Party and the net balance due. The Party owing the net balance due, as set forth in the billing statement, shall pay the other Party within 10 days from date of billing statement.

ARTICLE VIII

GENERAL PROVISIONS

8.01 *Reports and Information.* Each Party shall, upon request, furnish to the other Party such reports and information concerning its system operations as are reasonably necessary to enable each member of the Operating Committee to make informed judgment on all matters considered by the Committee.

8.02 *Uncontrollable Force.* No Party shall be considered to be in default in respect of any obligation hereunder if prevented from fulfilling such obligation by reason of an uncontrollable force. The term "Uncontroilable Force" shall incude, among others, such causes as failure of facilities, flood, earthquake, storm, lightning, fire. epidemic, war, riot, civil disturbance, labor disturbance, sabotage, delay in receiving supplies and materials, collision, or restraint or order of court or public authority having jurisdiction, or other causes beyond the control of the Party affected, and which by exercise of due diligence and foresight could not reasonably have been avoided. Any Party unable to fulfill any obligation by reason of an Uncontrollable Force shall remove said inability with reasonable dispatch; except that the settlement of strike or labor disturbance shall be entirely within the discretion of the Party incurring the strike or disturbance.

8.03 *Indemnity.* Each Party agrees to defend, indemnify, and hold harmless the other Party against any and all claims, liability, loss, damage, or expense caused by or resulting from the negligent acts or omissions of the indemnifying party, its employees or agents in connection with the performance of the Agreement.

8.04 *Waivers.* Any waiver at any time by a Party of its rights with respect to default of this Agreement or with respect to any other matter arising in connection with this Agreement, shall not be deemed a waiver with respect to any subsequent default or matter. Any delay, short of the statutory period of limitation, in asserting or enforcing any right under this Agreement, shall not be deemed a waiver of such rights.

8.05 *Right of Access.* Each Party will give authorized agents and employees of the other Party the right to enter its premises at all reasonable times for the purpose of reading or checking meters, for constructing, testing, repairing, renewing, exchanging, or removing any or all of its equipment which may be located on the property of the other Party or performing any work incident hereto.

8.06 *Successors and Assigns.* This Agreement shall not be assigned by either Party without first securing written consent of the other Party.

8.07 *Limitation as to Third Parties.* The signatories hereto shall be the only parties in interest to this Agreement. This Agreement is not intended to and shall not grant rights of any character whatsoever in favor of any person, corporation, association, or entity other than the Parties, and the obligations herein assumed by the Parties are sole-

ly for the use and benefit of the Parties. Nothing herein contained shall be construed as permitting or vesting in any person, corporation, association, or entity other than the Parties, any rights hereunder or in any of the electric facilities owned by the Parties or the use thereof.

8.08 *Arbitration.* Any controversy, claim, counterclaim, dispute, difference, or misunderstanding arising out of or relating to this Agreement, or to the breach thereof, excluding contribution, indemnification, or damages based on tortious conduct, shall be settled by arbitration before an arbitrator selected by the American Arbitration Association. The Party desiring arbitration shall demand such arbitration by giving written notice to the other Party setting forth the point or points in dispute. The arbitration shall be conducted in accordance with the Commercial Arbitration Rules of the American Arbitration Association then in effect, subject further to the qualification that the arbitrator named under said rules shall be competent by virtue of education and experience in the particular matter subject to arbitration. The arbitrator shall have jurisdiction and authority only to interpret, supply, or determine compliance with the provisions of this Agreement insofar as shall be necessary to the determination of issues properly appealed to the arbitrator. The arbitrator shall not have jurisdiction or authority to add to, detract from, or alter in any way the provisions of this Agreement. This provision shall survive the termination of this Agreement. Costs incurred in connection with the arbitration shall be paid in equal parts by the Parties unless the award shall specify a different division of costs.

8.09 *Notices.* Any notices, demands, or requests, required or authorized by this Agreement, shall be deemed

properly given if mailed postage prepaid, to the President, Northern States Power Company, Minneapolis, Minnesota, on behalf of Minnesota Company, and to the President, Wisconsin Company, Eau Claire, Wisconsin , on behalf of Wisconsin Company. The designation of the persons to be notified or the address of such person may be changed at any time by similar notice.

8.10 *Regulatory Approval.* This Agreement is subject to the regulation of any regulatory body having jurisdiction thereof.

ARTICLE IX

TERMINATION OF EXISTING AGREEMENTS

9.01 *Termination of Existing Agreements.* The following agreements are terminated as of the effective date of this Coordinating Agreement:

a. Interchange Agreement, dated April 15, 1960

b. Letter Agreement, dated March 8, 1960 (Supplement No. 1)

c. Agreement, dated September 30, 1960 (Supplement No. 2)

d. Supplemental Agreement, dated May 1, 1963 (Supplement No. 3)

e. Supplemental Agreement No. 4 dated July 15, 1964

f. Supplemental Agreement No. 5 dated June 9, 1965

g. Letter Agreement dated August 22, 1965 (Supplement No. 6)

h. Supplemental Agreement No. 7, dated December 29, 1965

i. Supplemental Agreement No. 8, dated May 16, 1966

j. Letter Agreement, dated May 31, 1967 (Supplement No. 9)

k. Supplemental Agreement No. 10, dated April 22, 1968

Termination of the foregoing Agreements shall have no effect on unpaid bills or other liabilities which may have accrued as of the date of termination.

ARTICLE X

TERM OF AGREEMENT

10.10 *Term of Agreement*. This Agreement shall become effective on January 1, 1971 and shall continue in effect for a period of ten years; and, shall continue in effect thereafter subject to cancellation by either Party hereto upon four years prior notice in writing given to the other Party. However, this Agreement is subject to cancellation by either Party in the event of: (1) default by the other Party in the performance of its obligation hereunder; (2) the other Party be adjudged bankrupt or shall go into voluntary or involuntary receivership; (3) the sale of all or a major portion of the facilities of the other Party; (4) the acquisition of another system or merger of a system with some other system so that the present contemplated method of operation would become undesirable in the opinion of either Party; (5) any occupation, production, transportation, sales, excise tax or any tax of similar nature is imposed upon electric power and energy sold by either of the Parties to the other; or (6) any restrictions

are imposed on the operation of streamflow or reservoir operations of the Wisconsin Company which in the opinion of either of the Parties will interfere with the value of the service to be rendered under this Agreement. Such cancellation shall be effective only after at least 90 days' prior written notice to that effect by a Party to the other Party.

ATTEST

By /s/ Harriet Rogge
Ass't. Secretary
By (Illegible)
Secretary

NORTHERN STATES POWER COMPANY (MINNESOTA)
By /s/ R. H. (Illegible)
President
NORTHERN STATES POWER COMPANY (WISCONSIN)
By /s/ (Illegible)
President

NORTHERN STATES POWER COMPANY (WISCONSIN)

Docket No. ———
Exhibit No. (NSP-103)

Amendment to Coordinating Agreement

Docket No. ———
Exhibit No.
Witness: Glenn B. Thorsen
Exhibit No. (NSP-103)

AMENDMENT TO COORDINATING AGREEMENT TO CONFIRM INTENT

By this Amendment, made as of this 22nd day of August, 1979, NORTHERN STATES POWER COMPANY, a Wisconsin corporation ("the Wisconsin Company"), and NORTHERN STATES POWER COMPANY, a Minnesota corporation ("the Minnesota Company"), confirm their interpretation of Article 7.02 of the Coordinating Agreement between them dated October 12, 1970, ("the Coordinating Agreement") with respect to the sharing of losses on a canceled generating plant project.

WITNESSETH:

WHEREAS, under the Coordinating Agreement the parties coordinate the development and operation of their generation and EHV transmission facilities and share fixed and variable costs of those facilities according to procedures set out in Article VII of the Coordinating Agreement;

WHEREAS, under Article 7.02 of the Coordinating Agreement the Companies share in fixed charges on generation facilities according to the ratio of their average peak demands as developed in Appendix A to the Coordinating Agreement;

WHEREAS, the Wisconsin Company was engaged with three other electric utilities in a project to construct Ty-

rone Energy Park, an 1100 megawatt nuclear generating station to be located in Wisconsin ("the project");

WHEREAS, the co-owners of the project originally agreed to share in its costs and ownership as follows:

The Minnesota Company	31.3%
The Wisconsin Company	36.3%
Cooperative Power Association	17.4%
Dairyland Power Cooperative	13.0%
Lake Superior District Power Company	2.0%

WHEREAS, the ownership arrangements were revised to transfer the Minnesota Company's share to the Wisconsin Company following a ruling of the Public Service Commission of Wisconsin that Wisconsin law prohibits the Minnesota Company, as a foreign corporation, from owning any portion of the project;

WHEREAS, in a decision issued March 6, 1979, the Public Service Commission of Wisconsin denied approvals which the co-owners of the project required under Wisconsin law in order to commence its construction;

WHEREAS, because of that decision the co-owners decided on July 24, 1979, to cancel the project;

WHEREAS, the Wisconsin Company's share of expenditures on the project to date amounts to approximately $40 million and its share of total expenditures on the project after all contract claims are resolved is estimated to be approximately $80 million;

WHEREAS, the Wisconsin Company intends to amortize its expenditures on the project as a loss over a five-year period beginning March 6, 1979;

WHEREAS, the project was planned in accordance with the Coordinating Agreement to meet the loads of both of the parties on an integrated system basis;

WHEREAS, under Article 7.02 of the Coordinating Agreement the Minnesota Company should share in the Wisconsin Company's expenditures on the project over the five-year amortization period; and

WHEREAS, in order to avoid a distortion in the Wisconsin Company's earnings, the Minnesota Company under Article 7.02 should also share in the Wisconsin Company's capital costs associated with unamortized expenditures on the project, but such costs will not be passed on to either company's ratepayers;

NOW, THEREFORE, the parties agree as follows:

1. Under Article 7.02 o fthe Coordinating Agreement, the Wisconsin Company's annual fixed charges on generating facilities for purposes of calculating payments by the Minnesota Company for the period March 6, 1979, through March 5, 1984, ("the amortization period") shall include provision for amortization of total expenditures on the project.

2. Under Article 7.02 of the Coordinating Agreement, the Wisconsin Company's annual fixed charges on generation facilities for purposes of calculating payments by the Minnesota Company for the amortization period shall also include capital costs associated with unamortized expenditures on the project. The Minnesota Company and the Wisconsin Company each commits itself not to pass these capital costs associated with unamortized expenditures through to its ratepayers.

3. Until the actual amount of cancellation costs is determined, payments by the Minnesota Company shall be based on estimates of those costs which shall be revised from time to time as necessary. Following any revision in the estimates, the Minnesota Company's payments shall be adjusted prospectively to reflect the unamortized balance of expenditures according to the revision. If the actual amount of cancellation costs is not determined until after the end of the amortization period, a final payment will be made by one company to the other in order to adjust the Minnesota Company's total payments for losses on the project to reflect the actual amount of those losses. That payment shall be made in the year in which the final determination of losses is made.

This clarification of the Coordinating Agreement shall be an integral part of that agreement.

Attest:
By /s/ (Illegible)
Secretary

NORTHERN STATES POWER COMPANY
(MINNESOTA)
By /s/ Donald (Illegible)
President

NORTHERN STATES POWER COMPANY
(WISCONSIN)
By /s/ John L. Carroll
President

By /s/ (Illegible)
Secretary

ALJ Decisions and Reports

Northern States Power Company (Minnesota),
Docket No. ER79-616
Northern States Power Company (Wisconsin),
Docket No. ER79-616
Initial Decision on Nuclear Plant Cancellation Loss

(Issued December 4, 1980)

Samuel Z. Gordon, Presiding Administrative Law Judge.

Appearances

George F. Bruder, Albert R. Simonds, Gene R. Sommers and *David A. Lawrence* for the Northern States Power Companies.

J. H. McLoone IV for the Minnesota Municipal Intervenors, Cities of Anoka, Arlington, Brownton, Buffalo, Chaska, Granite Falls, Kasota, Kasson, Lake City, North Saint Paul, Saint Peter, Shakopee, Waseca and Winthrop, Minnesota.

Frances E. Frances, John Michael Adragna, Robert C. McDiarmid, Rodney Wilson and *Ben Stead* for the Minnesota Public Service Commission, the North Dakota Public Service Commission and the South Dakota Public Utilities Commission.

Philip Mause and *William Sloshberg* for the Public Service Commission of Wisconsin.

J. Leroy Thilly, James F. Fairman and *Richard L. Olson* for the Wisconsin Intervenors, Cities of Black River Falls, Bloomer, Cadott, Cornell, New Richmond, Spooner, Westby, Whitehall and La Crosse, Wisconsin.

Alan Wolf and *L. Jorn Dakin* for the Staff of the Federal Energy Regulatory Commission.

I. Background

This proceeding arises from the cancellation of a 1100 MW nuclear generating project (Tyrone Energy Park) which was to be built in Wisconsin and involves, among other things: the amount of cancellation costs; the allocation of these costs between the Northern States Power Companies (Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin)[1] on the one hand and the other three co-owners of the project on the other, the allocation of the cancellation costs attributable to NSP as between the two NSP companies; the time period over which the costs shall be amortized; and the treatment of certain tax benefits.

The project was cancelled after the Wisconsin Public Service Commission denied it a certificate of public convenience and necessity on March 6, 1979. NSP estimates that the total concellation costs will be approximately $103.3 million, of which $75 million will be borne by the two NSP Companies and the balance of the other three co-owners of the project (Cooperative Power Association ("CPA"), Dairyland Power Cooperative ("DPC"), and Lake Superior Power District Company ("LSPD")).

On August 24, 1979, NSP-Minnesota and NSP-Wisconsin filed an Amendment to their Coordinating Agreement of October 12, 1970. Under the Agreement, which has been filed with the Commission in 1971 as a rate schedule, the two NSP Companies coordinate as a single system the development and operation of their generation and extra high

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[1]Northern States Power Company (Wisconsin) ("NSP-Wisconsin") is a wholly-owned subsidiary of Northern States Power Company (Minnesota) ("NSP-Minnesota"). The term "Northern States Power Company" ("NSP") without any state designation will be used to refer to the two companies collectively.

voltage (EHV) transmission facilities. They share the costs of ownership of generation, EHV transmission and related dispatching facilities, and share operation and maintenance costs and benefits arising from power transactions with other utilities.

In its Amendment, NSP sought to confirm that the cancellation costs attributable to NSP would be shared by the two NSP companies as fixed charges by the method set forth in the Coordinating Agreement. This would mean that approximately 87% of the concellation costs attributable to NSP would be borne by NSP-Minnesota and 13% by NSP-Wisconsin. NSP proposed that the costs would be amortized over a five-year period and NSP undertook not to earn a return on the unamortized balance by including the same in rate base. Since the cancellation costs were on an estimated basis, NSP proposed that a true-up adjustment would be made for actual costs as they became fixed and determined. NSP also proposed certain accounting treatment for the cancellation costs.

By order issued October 22, 1979, the Commission accepted the Amendment for filing and suspended its effectiveness for one day, as of March 7, 1979, subject to refund, and directed a hearing as to the justness and reasonableness of the Amendment. Intervention was granted to certain Minnesota[2] and Wisconsin cities[3] which had filed petitions

[2]The Minnesota Cities intervenors ("Minnesota Cities") are Anoka, Arlington, Brownton, Buffalo, Chaska, Granite Falls, Kasota, Kasson, Lake City, North Saint Paul, Saint Peter, Shakopee, Waseca and Winthrop, Minnesota. These fourteen Cities are municipal resale customers of NSP-Minnesota and are all members of the River Electric Association.

[3]The Wisconsin Cities intervenors ("Wisconsin Cities") are eight municipal resale customers of NSP-Wisconsin (the cities and villages of Black River Falls, Bloomer, Cadott, Cornell, New Richmond, Spooner, Westby, Whitehall, Wisconsin) and one city, LaCrosse, Wisconsin, which is served at retail by NSP-Wisconsin.

to intervene. Notices of intervention had also been filed by the Public Service Commissions of the States of Minnesota, Wisconsin and North Dakota, by the Public Utilities Commission of South Dakota and by the Department of Public Service of Minnesota. The Presiding Judge granted untimely petitions to intervene by the Minnesota Attorney General and the North Dakota Community Action Association; however neither of these participated in the hearing or filed briefs.

The Wisconsin Commission filed a motion to dismiss on December 6, 1979, on the ground that the Amendment was merely confirmatory of the cost allocation methodology in the Coordinating Agreement which had been approved by the Commission in 1971. The motion was denied by Commission order issued February 21, 1980. The Commission pointed out that the Amendment is a rate change filing as to which it had ordered a hearing to determine justness and reasonableness and that "a part of that determination involves the legitimacy of the costs which pass through the proposed rate. This includes the reasonableness and prudence of the costs sought to be amortized." (Order, mimeo. at 3.) Moreover, the Commission observed that among the issues raised by the Amendment were the prudence of NSP's carrying forward of the project and subsequent cancellation thereof, the length of the amortization period, appropriate accounting, and the method to adjust for changes in the estimated write-off amount (*Id.* at 2), matters as to which there may be disputed questions of fact which should be resolved by a hearing rather than on motion.[4]

[4]Since four state regulatory commissions had intervened and had raised multi-jurisdictional issues, the Commission granted a request for an informal joint conference under Section 1.37(c) of the Rules of Practice and Procedure (Order of February 21, 1980, at 2, 3). Such a conference was held but failed to resolve these issues.

The hearing commenced on May 27, 1980, and concluded on June 5, 1980. Initial and reply briefs were filed in due course.[5]

II. Allocation Of The Cancellation Costs Between The Two NSP Companies

Initially, the ownership shares in the Tyrone Project were divided as follows: NSP-Minnesota, 31.3%; NSP-Wisconsin, 36.3%; Cooperative Power Association, 17.4%; Dairyland Power Cooperative, 13.0%; and Lake Superior District Power Company, 2%. In 1978, the Wisconsin Public Service Commission ruled that since NSP-Minnesota was an out-of-state corporation it could not own a share in a Wisconsin generating facility. Hence, NSP-Minnesota transferred its ownership share to its subsidiary, NSP-Wisconsin. Thus, NSP-Wisconsin became the owner of a 67.6% share of the project, with the other co-owner's shares remaining unchanged.

We have noted that NSP estimates that the total cancellation costs will be approximately $103.3 million, of which $75 million is to be borne by the two NSP Companies, and the balance by the other co-owners. We discuss in Sections III and IV, below, the matters of the amount of cancellation costs and the portion attributable to the non-NSP co-owners of the project, with the other co-owners' shares remaining

[5]In another docket (ER80-181), NSP-Wisconsin filed for a rate increase, based in part on its share of the cancellation costs involved in the Tyrone project. The Commission's order of March 7, 1980 in ER80-181 made it clear that the determinations in the instant docket (ER79-616) would govern disposition of the issues of whether the amortization is proper, the length of the amortization period and whether the Coordinating Agreement affords a reasonable method of allocating amortization, and that these issues would not be relitigated in ER80-181 (Order of March 7, 1980, at 3).

the NSP share of the cancellation costs (whatever these costs may come to) as between the two NSP Companies.

The matter might be largely academic if it merely concerned a bookkeeping shifting of costs between the members of the same corporate family. However, the matter is far from academic since NSP-Minnesota, which serves at wholesale and retail in the States of Minnesota, North and South Dakota, has a different set of customers than NSP-Wisconsin, which serves only in Wisconsin. Thus, if some 87% of the NSP cancellation costs are allocated to NSP-Minnesota pursuant to the Coordinating Agreement, as proposed by the two NSP Companies, then these costs may become a part of NSP-Minnesota's rather than NSP-Wisconsin's, cost of service, and in turn may be passed on to the customers of NSP-Minnesota rather than the customers of NSP-Wisconsin.

In view of this situation, it is not surprising that intervenors the Wisconsin Public Service Commission and the Wisconsin Cities support NSP's position on cost allocation between the two NSP Companies. In contrast, the Public Service Commissions of Minnesota, South Dakota and North Dakota ("Minnesota-Dakotas Commissions"), as well as the Minnesota Cities, argue that the NSP cancellation costs should not be allocated to NSP-Minnesota at all or only to a very limited extent, and that the costs should remain with NSP-Wisconsin.[6]

NSP claims that NSP's share of the Tyrone total cancellation costs should be allocated between the two NSP Companies as a fixed charge pursuant to Article VII, Section

[6]The NSP cancellation costs are reflected on the books of NSP-Wisconsin since NSP-Minnesota had transferred its ownership interest in the Tyrone project to NSP-Wisconsin.

7.02 of the Coordinating Agreement (Ex. 1).[7] Under this Section, fixed charges for generating facilities are to be shared by the Companies pursuant to "participation ratios," as set forth in Appendix A to the Agreement. The participation ratios for each company are computed based on the company's five-year average contribution to coincidental summer and winter peak demands of the total (two-company) system. The average is a rolling one since it is computed for any given year by averaging the previous four years actuals plus an additional projected year.[8]

We agree that the Coordinating Agreement and its participation ratios methodology should govern the allocation of the cancellation costs between the two NSP Companies. They plan, develop and operate their systems on an integrated basis for the benefit of both Companies and their customers, and the Companies have agreed that the costs and benefits of such integrated system planning, facilities and operation will be shared in accordance with the terms of the Coordinating Agreement, irrespective of which company should happen to own particular facilities. The Tyrone project was initiated, planned and carried forward to meet the needs and requirements of both NSP Companies as part of an integrated system and both would have shared in the costs and benefits of the project, had it been built, in accordance with the terms of their Coordinating Agreement. It is

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[7]NSP's position in this respect is supported by the Wisconsin Public Service Commission, the Wisconsin Cities, and the Staff of this Commission.

[8]Fixed operating and maintenance costs for generating facilities and power transactions, as well as fixed charges for EHV transmission facilities and operating and maintenance costs for such facilities, are also shared in accordance with the participation ratio methodology (Article VII, Sections 7.03, 7.05, 7.06). Variable operating and maintenance costs for generating facilities and power transactions are shared according to each company's ratio of monthly Kwh requirements to the total of such requirements by the two companies (Section 7.04).

only just and reasonable that the cancellation costs should be shared by the two companies in the same fashion that the costs of the project would have been shared had it come on line.

The two Companies have set forth in their contractual Coordinating Agreement the participation ratios method for sharing fixed costs of generation (and other) facilities. That method, based on each company's five-year rolling average share of combined NSP system summer and winter peak demands, is just and reasonable, has been agreed to by the parties, and has been applied for the past ten years without complaint by anyone. The coincidental peak demand method for allocating fixed costs has long been favored by this Commission. The use of two peaks—summer and winter—and the five year rolling average, helps prevent distortion caused by unusual weather conditions and recognizes each company's relative contribution to combined system summer and winter peak demands. (3 Tr. 362, 396; 7 Tr. 1091).

The Coordinating Agreement does not expressly address the matter of cost allocation in the event of project cancellation. However, the Agreement does specifically provide for the allocation of fixed costs of generation (and transmission). The Tyrone cancellation costs are a species of fixed costs. These costs comprise such matters as design and engineering, nuclear steam supply and turbine generators (Exs. 14, 26). The costs are included as "Components of Construction Costs" in the Uniform System of Accounts[9] and would be included as a part of the cost of electric plant included in rate base on which depreciation and a return

[9]Uniform System of Accounts, Electric Plant Instructions, Section 3 (18 C.F.R. Part 101, Rev. as of April 1, 1980).

would be afforded if the plant went in service. The cancellation costs are, obviously, not a kind of variable cost since they do not change with the amount of energy produced. Thus, the Tyrone cancellation costs are fixed charges which are properly allocated to the two NSP Companies in accordance with the participation ratios as provided in Section 7.02 of the Coordinating Agreement.

If any doubt on this score remains, it is removed by the two NSP Companies' course of conduct and agreements subsequent to the execution of the Coordinating Agreement in 1970. Thus, the Companies shared cancellation costs of other projects (Shibley, Sherco 4) arising prior to the Tyrone cancellation, in accordance with the Coordinating Agreement, since those other aborted projects were, like Tyrone, planned to meet the integrated needs of the total NSP system. While those cancellation costs (some $7.7 million; 7 Tr. 967) were considerably smaller than Tyrone's, the principle of sharing project cancellation costs as fixed charges pursuant to the Coordinating Agreement remains the same.[10]

Regarding the Tyrone project itself, the two NSP Companies entered into a letter agreement on March 17, 1978 (Ex. 91) confirming that any Tyrone cancellation losses would be shared by the Companies in accordance with Section 7.02 of the Coordinating Agreement. The letter agreement was presented to the Wisconsin Commission and was intended to and did influence the action of that Commission to enable the project to go forward at that time. Further, the Amendment to the Coordinating Agree-

[10]The cancellation costs on Shibley and Sherco 4 were initially incurred by NSP-Minnesota but were shared by NSP-Wisconsin. That the shoe is now on the other foot makes it no less a shoe.

ment filed in this proceeding further demonstrates the NSP Companies' desire and intent to have the Agreement govern the allocation of the Tyrone loss.

Thus, there is plain and sufficient evidence in the NSP Companies' contractual undertakings and course of conduct for allocating NSP's share of the Tyrone cancellation costs in accordance with the Coordinating Agreement and the participation ratios for the sharing of fixed charges as provided in the Agreement. But, over and beyond this, we approve such allocation for the Tyrone cancellation costs because, as found above, it is just and reasonable. It is unnecessary, therefore, to go so far as the Wisconsin Commission which argues that, under *FPC v. Sierra Pacific Power Company* (350 U.S. 348 (1956)), the Coordinating Agreement is a species of fixed rate contract which *must* be applied to the Tyrone loss by this Commission, absent a finding that the Agreement is contrary to the public interest (Initial Br., p. 6).[11] This Commission has impliedly rejected this argument by its orders of October 22, 1979, and February 27, 1980, setting this case for hearing on the justness and reasonableness of the Amendment to the Coordinating Agreement, and we do not adopt the Wisconsin Commission's argument here.[12]

The contentions advanced by the Minnesota-Dakotas Commissions and the Minnesota Cities contrary to our conclusion that the Tyrone cancellation costs attributable

[11]The Wisconsin Commission has somewhat softened its position by arguing in its reply brief, in the alternative, that the Commission should apply the Coordinating Agreement and the Amendment because they are just and reasonable (Reply Br., p. 13). Our findings and conclusion that the Agreement and Amendment are just and reasonable, would include a finding that they are not contrary to the public interest.

[12]NSP itself does not adopt the Wisconsin Commission's *Sierra-Mobile* argument, but instead contends, as we have found, that the Coordinating Agreement should be applied because it is just and reasonable to do so.

to NSP should be allocated between the two NSP Companies in accordance with the Coordinating Agreement (and, specifically, in accordance with the participation ratio method for sharing fixed charges) are not persuasive.

First, they contend that the Wisconsin Public Service Commission's decision of March 6, 1979 (Ex. 12) denying certification of the project was based exclusively on its view of the generation and energy needs and capacity of NSP-Wisconsin alone and did not consider the integrated, overall needs and capacity of the entire NSP system. They argue that since the Coordinating Agreement and the Tyrone project were based on overall NSP system needs and capacity, and since the Wisconsin Commission rejected the fundamental premise of the Agreement and the Tyrone project, the Agreement should not be used to allocate the loss and that the loss should be attributed solely to NSP-Wisconsin.

The Wisconsin Commission's decision denying project certification is none too clear, and while its primary emphasis is on the needs and capacity of NSP-Wisconsin, the Commission did take into consideration the needs and capacity of the overall NSP System. See, e.g., Order Denying Authority to Build Tyrone Energy Park, March 6, 1979, (Ex. 12), at 6, 9, 10, 11, 13. That the Wisconsin Commission was concerned with overall NSP system needs and capacity is manifest since it directed NSP-Wisconsin to file an application for a coal-fired baseload plant appropriately sized "for the use of the combined system, if the

combined system is, as the Commission urges, retained and strengthened" (*Id.* at 13).[13]

In any event, for the purposes here, the reasons why the Wisconsin Commission rejected the Tyrone application are relatively unimportant. What is important are the reasons why the Tyrone project was planned and carried forward. No one disputes that this was prudently done to meet the combined, integrated needs of the entire NSP system, rather than just the needs of one or the other of the NSP Companies. Nor does any one dispute that if the project had been built it would have operated for the benefit of the combined, integrated system and that the NSP Companies would have shared in the costs in accordance with the formula set forth in the Coordinating Agreement. Even if, arguendo, the Wisconsin Commission acted incorrectly in denying project certification, this is no reason for refusing to apply the Coordinating Agreement for sharing the cancellation loss between the NSP Companies. NSP-Minnesota which would have been responsible for about 87% of the NSP Tyrone load, should be responsible for the same percentage of the cancellation loss attributable to the NSP Companies. Clearly, the sins of the Wisconsin Commission, if indeed they were sins, should not be visited entirely on NSP-Wisconsin, as urged by the Minnesota-Dakotas Commissions and the Minnesota Cities.

Second, allied to the foregoing, but cast in a different framework, is the argument of the Minnesota-Dakotas Commissions that the Wisconsin Commission acted unconstitu-

[13]NSP-Wisconsin has since filed an application with the Wisconsin Commission for certification of a 660 MW coal-fired plant which is planned to meet overall NSP system requirements. This is not greatly different in size from NSP's share of the Tyrone 1100 MW plant (approximately 750 MW).

tionally in denying project certification because of federal pre-emption of the field of nuclear plant licensing, that NSP-Wisconsin thus acted imprudently in failing to prosecute an appeal from that decision,[14] and that, hence, the cancellation loss must be borne solely by NSP-Wisconsin.

We need not be drawn into the thicket of federal constitutional pre-emption beyond pointing out that it is not clear beyond peradventure that such pre-emption occurs in the instant situation. For while it appears that the Atomic Energy Act grants exclusive jurisdiction to the Nuclear Regulatory Commission in the area of radiation hazards, Section 274 of the Act provides that a State's authority to regulate for other purposes is not affected (42 U.S.C. Sec. 2021(k)). Here, the Wisconsin Commission's denial turned on lack of need for the nuclear plant, economic disbenefits, and superiority of alternative means of generation. Probably, only a decision by the United States Supreme Court could definitely resolve the issue of federal pre-emption in this wholly contested area.[15] Moreover, it should be pointed out that while the proceedings before the Nuclear Regulatory Commission led to the issuance of a construction permit for the Tyrone project in December 1977, the Atomic Safety and Licensing Appeal Board of the Commission, on March 17, 1978, in affirming a decision on the need for the project to meet the integrated NSP system needs, had remanded

[14] On April 6, 1979, in order to preserve their options pending further consideration of the matter, the Tyrone co-owners filed an appeal with the Circuit Court for Eau Claire County. But following a decision on July 24, 1979 by the co-owners to terminate the project, the appeal was withdrawn.

[15] So too, with the Minnesota-Dakotas Commissions' argument that the Wisconsin Commission's decision was an unconstitutional burden on interstate commerce.

on two issues[16] (2 Tr. 152-155; Ex. 11). No decision had been reached on those issues at the time of project cancellation.

A second option open to NSP was that held out, indeed directed by the Wisconsin Commission in its March 7, 1979 decision denying project certification: namely, to file application for a coal-fired plant appropriately sized to meet the overall NSP system needs, and the Wisconsin Commission undertook to expedite consideration of such an application (Ex. 12, at 16).

NSP's decision to abandon the Tyrone project was made primarily on the basis that even if an appeal from the Wisconsin adverse decision were successful, the project could not be built and placed in operation before 1989 *at the earliest;* the NSP system, however, would be short of generating capacity unless a new generating unit were added in the period 1985-89 (2 Tr. 112, 113). Moreover, the appellate review processes of the Nuclear Regulatory Commission had not been completed and issues previously settled could be reopened "because of the mere passage of time or as a result of the accident at Three Mile Island and any resulting changes to NRC standards" (2 Tr. 112). On the other hand, the Wisconsin Commission had urged and directed the filing of an application for a coal-fired plant and there was good reason to believe that such a plant could be built within the necessary 1985-89 time period.

Faced with the choices, as discussed above, it is concluded that NSP was not imprudent in cancelling the Tyrone project but that its decision to do so was reasonable under

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[16]Those issues concerned the effect of the transfer of NSP-Minnesota's ownership share of the project to NSP-Wisconsin and the environmental and health effects of changes in radon radiation release values (Ex. 11, at 5-7).

all the circumstances.[17] Moreover, no party in this proceeding contends that NSP was imprudent in initiating and carrying forward the project up to the date of cancellation.

Third, other criticisms voiced by the Minnesota Cities are without merit or are insufficient to rebut the use of the Coordinating Agreement's participation ratios to allocate the loss. Thus, the Cities' witness, Mr. Dahlen, contended that the Agreement imperfectly allocates transmission losses and purchased power expenses. Without analyzing the merits of these contentions (see, e.g., the refutation by the Wisconsin Cities, Initial Br., at 47-49), they are simply beside the point. For the Tyrone cancellation loss has nothing whatever to do with purchased power expense or transmission losses and no part of the Agreement bearing on such matters is used to allocate the cancellation loss. We are not here reviewing the merits of the Coordinating Agreement in all its aspects; but simply deciding whether the Tyrone loss should be allocated between the NSP Companies as a fixed charge pursuant to the participation ratios as set forth in Section 7.02 of the Agreement.

Mr. Dahlen also contends that the participation ratios method underallocates the loss to NSP-Wisconsin because the ratios are based on a rolling five-year average of coincident demands whereas NSP-Wisconsin's demands are expected to grow more rapidly than NSP-Minnesota's. While it is true that use of the five-year average will cause some lag in reflecting changes in relative demands between the two companies, it is not at all clear that NSP-Wisconsin

[17] The Minnesota-Dakotas Commissions' attempt to lay the "blame" for the Tyrone cancellation decision on NSP-Wisconsin alone is strange since this Company was wholly owned and controlled by NSP-Minnesota and no doubt the parent company directed or, at least, acquiesced in that decision.

will grow more rapidly than NSP-Minnesota or that any change in relative growth which will actually occur will materially affect the ratios. Moreover, since we will order a targeted ten-year amortization period (rather than a five-year period as advocated by NSP), changes in the relative demands by the two companies occurring over a longer period will be more accurately reflected in the ratios. Furthermore, use of the five-year rolling average (rather than, say, a single year) minimizes distortions occurring in any one year. Moreover, the ratios are based on using an average of summer and winter coincident peaks, rather than a single peak, and the two-peak method favors the Minnesota Company (3 Tr. 396).[18]

The Minnesota Cities witness, Mr. Stocke, makes a more far-reaching proposal. As an alternative to his view that 100% of the Tyrone loss attributable to NSP should be allocated to NSP-Wisconsin on the basis that it was the Wisconsin Commission which caused the loss (a view which has been rejected, above), the witness would allocate 91% of the loss to NSP-Wisconsin on the theory that if the Tyrone plant had been built, 91% of the energy supplied by the plant would have been used by NSP-Wisconsin and the balance by NSP-Minnesota.[19] This theory is based on a number of assumptions, including that NSP-Wisconsin would not make any firm purchases from NSP-Minnesota

[18]This is so because NSP-Minnesota's peak demand, as well as the combined two-company peak, generally occurs in the summer, whereas NSP-Wisconsin's peak generally occurs in the winter. If only a single coincident peak method were used to compute demand responsibility, more of the fixed charges would fall on NSP-Minnesota than under the two-peak method used in the participation ratios (3 Tr. 396, 7 Tr. 1091).

[19]Mr. Stocke declined to advocate adoption of the one or the other of his alternative recommendations (100% or 91% allocation to NSP-Wisconsin) as superior (6 Tr. 891-892).

or any other source during the forty-year expected life of the Tyrone plant and would not build any new generating facilities during that period (6 Tr. 850-851, 857, 867).[20]

But such assumptions are unrealistic and untenable. They completely ignore, as Mr. Stocke admitted, that NSP-Wisconsin, which for many years has been paying, via the Coordinating Agreement and previous exchange agreements, for installed generation located in NSP-Minnesota's service area in Minnesota and elsewhere outside Wisconsin, has a contractual right to a share in such extra-Wisconsin generation (6 Tr. 865-869, 927, 935-936). They assume that the Tyrone plant's output would be reserved exclusively for NSP-Wisconsin, with the latter selling only any energy surplus to its needs to NSP-Minnesota. This, of course, is contrary to NSP-Minnesota's contractual rights under the Coordinating Agreement to the largest share of the Tyrone output. And, Mr. Stocke would ignore the fact that since NSP-Minnesota would be paying approximately 87% of the investment costs in Tyrone under the Coordinating Agreement it could not be relegated merely to some small portion of Tyrone's generation which would be surplus to NSP-Wisconsin's needs.

In short, the witness's theory completely ignores the purposes of the Tyrone project, would destroy the single, integrated NSP system planning and operation that the project was designed to serve, and eliminates the parties'

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[20]Among Mr. Stocke's other assumptions are that NSP-Wisconsin's load would grow at the rate of 4% a year over the 40-year period (a figure that the Wisconsin Commission had found to be too high, Ex. 12); that the plant's life would be 40 years (although the witness conceded that nuclear plants were generally estimated to have a 30-35 year life (6 Tr. 857); and that a discount factor of 10% should be applied to the witness' load projections (although he conceded that such a factor was based on the time value of money and had no real relevance to load projections (6 Tr. 937-938).

cost and benefit contractual undertakings in their Coordinating Agreement under which they have operated for many years without complaint. As such the theory must be rejected and with it Mr. Stocke's recommendation that 91% of the cancellation loss must be allocated to NSP-Wisconsin.

On all the foregoing, it is found and concluded that it is just and reasonable that the Tyrone cancellation loss attributable to NSP shall be shared and allocated between the two NSP Companies in accordance with the participation ratios, as provided in the Coordinating Agreement.

III. Limitation Of Liability of Other Co-Owners

We have noted, above, that the co-owners of the project had these ownership interest: NSP-Wisconsin (67.6%); Cooperative Power Association ("CPA," 17.4%); Dairyland Power Cooperative ("DPC," 13.0%); and Lake Superior Power District Company ("LSPD," 2.0%). (See Construction and Ownership Agreement, dated June 30, 1977, Ex. 85; Supplement No. 3, dated March 10, 1978, Ex. 85.) Supplement No. 2 to the Construction and Ownership Agreement, dated February 25, 1978 (Ex. 85) limited the combined financial obligation of CPA and DPC to $5 million (Section 27.12). However, Supplement No. 4 to the Agreement, dated June 29, 1978 (Ex. 85) increased the limitation for both companies to a total of $22 million—$12 million for CPA, and $10 million for DPC (Section 27.12(A), (B) and (C)). No financial limitation was made respecting the other co-owner, LSPD, and its ownership share of 2%, continues to be the measure of its financial obligation for the total Tyrone cancellation loss.

The issue here arises because in allocating the total Tyrone cancellation loss, NSP proposes to recognize the \$22 million limitation on the financial obligation of DPC and CPA, even though the \$22 million is less than the share of the total loss which DPC and CPA would bear if the loss were allocated to them according to their ownership interests in the project. On the basis of NSP's estimates of the cancellation loss, the loss allocable to DPC and CPA on the basis of their ownership interests would exceed the \$22 limitation by approximately \$7 million (4 Tr. 483, Ex. 14). NSP proposes that the amounts not allocable to DPC and CPA because of the \$22 million limitation will be allocated to NSP-Wisconsin and shared by NSP-Minnesota, as discussed in Section II, above. Ultimately, then, the amounts not allocable to DPC and CPA will be passed on to the customers of the two NSP Companies.

The Wisconsin and Minnesota Cities and the Minnesota-Dakotas Commissions contend that NSP acted imprudently in agreeing to the \$22 million limitation and that any share of the cancellation loss which is not allocated to DPC and CPA because of that limitation must be absorbed by the NSP stockholders and may not be passed on to the NSP customers. These contentions are without merit.

DPC and CPA, as rural electric cooperatives or associations of such co-operatives, were subject to the rules and regulations of the United States Rural Electrification Administration. The Construction and Ownership Agreement and the various Supplements thereto, make it clear that the participation, rights and obligations of DPC and CPA were at all times subject to the approval of the Administrator of REA (see, e.g., initial Agreement dated June 30, 1977, Section 27.12; Supplement No. 2, Sections 21.3,

27.12; Supplement No. 4, Section 27.12(A), (J)). REA approval was necessary because, among other things, DPC and CPA were dependent on REA for long-term financing and also for short-term (pre-project certification) financing. Interim or short-term financing is provided by the National Rural Utilities Co-operative Finance Corporation ("CFC") but "CFC interim financing is provided subject to REA approval, which REA approval is necessary for CFC up to the level of the interim financing" (Ex. 8, p. 2).

On February 23, 1978, REA granted loan guarantee commitments in the amount of \$223.9 million to CPA and \$167.3 million to DPC (Exs. 50, 49). However, those commitments were subject to numerous conditions including that these cooperatives must submit satisfactory evidence that all necessary Tyrone project state and federal governmental licenses, permits and authorizations had been obtained or were not unobtainable (Exs. 49, 50, p. 2 of 2, item 7). No such evidence was submitted to REA and indeed, after the rejection of the project by the Wisconsin Commission on March 6, 1979, could be submitted. That the parties themselves did not regard the February 23, 1978 loan guarantee commitments as the REA approval called for in the Construction and Ownership Agreement is seen from the fact that the subsequent Supplements to the Agreement still called for the obtaining of REA approval (see, e.g., Supplement No. 4, Section 27.12(A), (B), (C), (J). On this record, no such approval was ever granted.

REA, however, was willing to grant approval to DPC and CPA to undertake certain limited, interim, pre-certification project financial obligations. The limit for the two companies was \$5 million, as expressed in Supplement No. 2 of February 24, 1978, and \$22 million in Supplement

No. 4 of June 29, 1978 (Ex. 85). The $22 million was the maximum which had been approved by REA (Ex. 8, affidavit of Mr. Frank W. Linder, general manager of DPC).[21]

Mr. Linder's testimony (Ex. 8) further establishes that DPC and CPA were not free, absent REA approval, to increase their financial obligations in the project and that if NSP insisted on their exceeding the $22 limitation approved by REA the cooperatives probably would have had to pull out of the project and NSP would have had to buy out their interests. (See also testimony of NSP's witness Thorsen, 4 Tr. 510-512.)

Under these circumstances, NSP acted reasonably and prudently in entering into Supplement No. 4. It thereby succeeded in raising the financial limits of DPC and CPA from $5 million to $22 million, thus saving the greater amount from being imposed on NSP and its ratepayers. NSP succeeded in keeping the cooperatives in the project at a time when it became apparent that the project faced great public opposition in Wisconsin, as well as the opposition of some of the members of the Wisconsin Commission and its staff. Moreover, NSP gained the option, if DPC and CPA were not successful in getting REA approval to exceed the $22 million limitation, to purchase the portion of the cooperatives' ownership interest in excess of the REA limitations (Supplement No. 4, Section 27.12(G) and (H)). And if NSP exercised that option, the cooperatives were committed to purchase the associated power for a five-year period (Section 27.12(H)). If the project were completed, NSP would have exercised its option (3 Tr. 393), thereby gaining a greater ownership interest in a source of economi-

[21]NSP offered to make Mr. Linder available for cross-examination, but no party wished to avail itself of this opportunity (4 Tr. 537).

cal power for its ratepayers. And the five-year purchase commitment would aid in securing NSP ratepayer protection in the early years of the project life.

There is no evidence that NSP failed to bargain hard and in good faith in entering into the Construction and Ownership Agreement and the various Supplements thereto, including Supplement No. 4. Given the various choices and options available, we find and conclude that NSP acted reasonably and prudently in agreeing to the limitations on liability of DPC and CPA.

There is another co-owner of the Tyrone project, Lake Superior District Power Company (LSDP), with 2% ownership interest (Ex. 85). In contrast to DPC and CPA, no agreement was made to limit LSDP's share of the cancellation loss below its 2% interest and NSP has assigned 2% of the loss to LSDP. The Wisconsin Cities contend, however, that NSP-Minnesota is in the process of acquiring LSDP and that, hence, the latter's load should be attributed to NSP-Minnesota in figuring the participation ratios under the Coordinating Agreement (witness Sack, 5 Tr. 762-63). We do not agree with this contention.

The LSDP acquisition is pending before the Securities and Exchange Commission and a decision is not expected until next year. If the acquisition is approved, NSP-Minnesota and LSDP will then file with FERC a coordinating agreement to equitably assign costs in light of the new affiliation (3 Tr. 397). The plan is that no portion of LSDP's percentage interest will be allocated to the NSP Companies and no portion of NSP-Wisconsin's percentage interest in Tyrone will be allocated to LSDP. Thus the filing in the instant proceeding will not affect the allocation of the Tyrone loss either to LSDP from the NSP Companies or

from LSDP to the NSP Companies (Thorsen, 3 Tr. 397-98). Until the acquisition is completed and a new coordinating agreement is filed dealing with LSDP, it is premature and unnecessary to deal with the matter here.

Moreover, even if the LSDP load is attributed to NSP-Minnesota, this will have a *de minimis* effect on the participation ratios. For the total difference to NSP-Wisconsin would be only $7,125 in the year 1981 of which only approximately $641 would be reflected in reduced rates to NSP-Wisconsin's jurisdictional customers (or $5 per month per wholesale customer). 4 Tr. 523.

IV. Amount of the Cancellation Loss, the Time Period for Its Amortization, and Required Conditions

A. Introduction

We have found, *supra,* that the amount of the Tyrone cancellation loss attributable to NSP, including amounts in excess of the $22 million limitation on liability of CPA and DPC, shall be shared by the two NSP Companies in accordance with their participation ratios as set forth in the Coordinating Agreement. In this Section, we discuss the proper amount of the cancellation loss to be amortized (written-off), the time period for such amortization, and the imposition of appropriate conditions to the amortization.

NSP estimates that the total cancellation loss (*i.e.,* the loss to be shared by all four co-owners of the project) is $103.3 million, of which $75 million is attributable to NSP (Ex. 14). Of the $75 million, $35 million represents payments actually expended by NSP (less salvage) and $40 million represents NSP's estimate of the costs of terminating some 250 contracts with vendors and suppliers of goods and services for the project. NSP's initial filing

had projected the loss as $80 million, but it has reduced this amount to $75 million to reflect salvage value, chiefly of nuclear fuel.

NSP proposes to amortize the $75 million loss over a five-year period and, pursuant to the Commission's Opinion No. 49,[22] NSP does not seek any return or recovery of carrying charges on the unamortized balance. NSP recognizes that the $75 million is an estimate of the loss (albeit it claims that the estimate is reasonable) and that the actual amount of the loss will not be definitely ascertained until it settles all the vendor claims. Hence, NSP proposes to make quarterly adjustments and a final true-up adjustment so that only the actual amount of the loss paid will ultimately be shared by the two NSP Companies in accordance with the Coordinating Agreement. NSP believes that all vendor claims can be settled (or, if need be, adjudicated) within the five-year amortization period but, if that does not eventuate, the final true-up adjustment will occur subsequent to that period. Thus, under the method proposed by NSP, the $75 million estimated loss does not represent the definitive amount of the cancellation loss or even a cap or ceiling on such amount. The $75 million would be adjusted up or down to conform to the amounts actually and prudently paid in settlement of the vendor claims.

The foregoing most directly affects the allocation of the cancellation loss between the two NSP Companies. However, such allocation may not automatically govern the ratemaking consequences either at the federal (resale rates) or state (retail rates) level. In recognition of this, NSP states that it is willing to make such reports and filings which

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[22] *New England Power Company*, Opinion No. 49, Docket Nos. ER76-304, *et al.*, July 19, 1979.

the federal and state regulatory bodies may require, within their jurisdictional authority, to reflect the allocation of the loss between the two NSP Companies in their respective resale[23] and retail rates. In this connection, NSP maintains that since it has here requested and agreed that the five-year amortization period shall commence in March, 1979 (the date when the Wisconsin Commission decided to deny project certification) and since it has not filed for rate increases reflecting the amortization until more than a year thereafter, the stockholders of NSP will be absorbing some $22.4 million of the $75 million cancellation loss (Ex. 7). Intervenors dispute this contention since it assumes that at the end of the five-year amortization period NSP's rates will no longer reflect any amounts for amortizing the loss.

NSP maintains that its $75 million estimate of the cancellation loss is fair and reasonable that it is a net figure after major salvage items have been excluded, that the quarterly and final true-up adjustments will ensure that the amortization or write-off will track only actual cancellation costs, that it is proper to include AFUDC (both the debt and equity portions thereof) accruing to March, 1979, in the $75 million estimate, and that a five-year amortization period is fair since it will write-off a non-productive asset from NSP's books in a reasonably short period consistent with a reasonable impact on rates to customers.

The Intervenors dispute virtually all the foregoing. They variously maintain that NSP's estimate of the cancellation

[23]In NSP-Wisconsin's 1980 resale rate filing (ER80-181), this Commission held that the disposition of the issues of the propriety of the disposition of the issues of the propriety of the amortization, allocation between the NSP Companies, and length of the amortization period, in the instant docket (ER79-619) would govern in docket ER80-181 (Order of March 7, 1980, Docket No. ER80-181).

loss is excessive and speculative and will result in overpayments by the ratepayers so that the estimate must be rejected in toto or considerably scaled down; that salvage has not been appropriately considered in NSP's estimates; that the amortization period should be extended to thirty years (the expected life of the Tyrone plant had it been built) or to 15 years in order to lessen the impact on ratepayers; and that all AFUDC or at least the equity portion thereof should be excluded from the write-off since the risk of non-completion of the project which will never be used or useful to the customers must be borne by the stockholders.

The Commission Staff, recognizing the speculative nature of the estimated loss, advocates a variable amortization period targeted at ten years since during such period all losses will become fixed and definitive. While expressing misgivings as to the quality of NSP's proofs, the Staff is apparently willing to permit use of NSP's estimates (reduced by some $5 million for debt and equity AFUDC) as a basis for a targeted or tentative ten-year amortization of approximately $70 million or $7 million a year. NSP will proceed to write-off $7 million each year until all the prudently incurred cancellation costs are paid. This will result, for example, in an amortization period of eight years if the costs are $56 million, or twelve years if the costs are $84 million. Hence, under Staff's recommendation the amortization period will be a variable one, although the same dollar amount will be written-off each year, thus contributing to rate stability.

We address, below, the questions of the amount of the cancellation loss which is to be amortized (including whether AFUDC may be included in computing the loss), the amortization period, and the imposition of appropriate conditions to the amortization.

B. The Amount Of The Cancellation Loss

We have noted that NSP's estimate of $75 million in cancellation loss is made up of two parts: $35 million in actual expenditures (net, after salvage), and $40 million in estimated expenditures for terminating some 250 vendor contracts. Intervenors' objections center chiefly on the $40 million portion, but some of them also object to the $35 million portion on the ground that all salvageable items have not been excluded from the loss.

1. Salvage

In arriving at the $35 million figure for actual expenditures, NSP determined that $4,743,994 represented salvage items (nuclear fuel, land transfer, railroad trackage and meteorological tower) of which NSP's share is $4,660,145 (3 Tr. 382-383). NSP reduced its actual expenditures figure by $5 million in arriving at the $35 million portion of the $75 million. Also, as shown in Exhibit 14, NSP excluded an additional $1 million for land transfer or salvage. Thus the $35 million claimed by NSP in actual expenditures for the Tyrone loss is an amount net of $6 million in salvage, which has already been deducted. Probably all significant salvageable items comprehended in the actual expenditures to date have thus already been deducted (3 Tr. 383).[24] However, if any further items are salvaged, they must be deducted from the write-off amount and the ten-year variable amortization period with attendant reports, which we shall direct herein, will help ensure that this is accomplished.

[24]After March 1979, when the Tyrone project failed to achieve certification by the Wisconsin Commission, NSP for a time sought to market the entire Tyrone package. By May 1980, NSP concluded this could not be done and abandoned this effort (2 Tr. 181, 3 Tr. 383).

Moreover, NSP will be under a continuing duty to use its best efforts to identify and salvage all salvageable items so as to reduce the write-off amount.[25]

It is found and concluded, therefore, that NSP's estimates are not invalidated on the ground that they do not properly deduct for salvage.

2. NSP's Use Of Estimates For The Write-Off

Unlike the $35 million in actual expenditures, NSP's estimate of $40 million for costs of terminating vendor contracts does not represent monies already actually expended by NSP, rather the $40 million represents NSP's estimate of future expenditures. The Intervenors contend that such estimate is so unreasonable, speculative and uncertain that it may not be included in the write-off amount at all or must be considerably scaled down. The better procedure, they argue, is to permit a write-off of vendor cancellation claims only after each large claim or group of smaller claims is definitely fixed in amount by NSP's settlement with the vendors or, if need be, by litigation. The write-off period would be the same number of years for each claim or group, but the beginning and end of the period would vary depending on when each claim or group was resolved. In this fashion, overpayments or prepayments by the ratepayers will be avoided. We find such arguments unpersuasive.

First, estimates may be used in computing the amount of the write-off so long as they are reasonable, especially where, as here, the estimates will be adjusted to conform

[25]Mr. Sack, one of the witnesses for the Wisconsin Cities, identified items which he believed might have other uses than for Tyrone, but he did not conclude that such other uses were actually possible (5 Tr. 746).

to the actual expenditures. The Commission has for some years approved the use of estimates in deriving a Period II or test year cost of service for electric ratemaking purposes, so long as the estimates are reasonable.[26] *A fortiori,* estimates may be used here in computing the write-off amount since the variable amortization period and attendant reports and required conditions herein ordered will ensure that no more or less than the actual, prudent cancellation costs will be amortized.

In this situation, NSP's estimate of $40 million in contract termination costs is reasonable as a means to initiate the write-off process. Some 250 contracts with vendors are involved. Of these, as designated in Exhibit 14, "nuclear steam supply" (estimated termination cost of $21.8 million) is a contract with Westinghouse; "turbine generator" (estimated termination cost of $3.8 million) is a contract with General Electric; and "balance of plant" (estimated termination costs of $20.4 million)[27] are contracts with about 250 other vendors and suppliers of goods and services for the project. NSP's witness, Dr. Max DeLong, was directly responsible for preparing the estimates, which were reviewed by NSP witness, Mr. Roland Jensen. Both attested to the reasonableness of the estimates (2 Tr. 115, 3 Tr. 242), although Dr. DeLong was more familiar with the details. He was Project Engineer for the Tyrone project since March 1974 and is currently the Project Manager (3 Tr. 240). In preparing the cancellation estimates, Dr. DeLong had the advice and assistance of NSP's in-house and outside counsel and engineering staffs; Mr. Jensen; Bechtel Corp. (NSP's

[26]18 C.F.R. 35.13(b)(4)(iii).

[27]The termination cost amounts stated in the text exceed $40 million since they include the co-owners' share of the costs.

architect-engineer for the project); and the SNUPPS[28] engineering and administration staff. Dr. DeLong arrived at a range of estimates for the cancellation of the Westinghouse and "balance of plant" contracts, and the amounts included in Exhibit 14, which are relied upon by NSP in this proceeding, are at about the mid-point of that range. The G. E. estimate in that Exhibit is slightly above G.E.'s own estimate. In arriving at the estimates, Dr. DeLong made breakdowns of the Westinghouse, G. E., and "balance of plant" contracts into engineering, equipment, materials and supplies, and termination charges (see Ex. 22, prepared by the Wisconsin Cities on the basis of data supplied by NSP). The termination charges included more than just vendor lost profits, but also additional charges based on cancellation of the contracts (2 Tr. 203; 3 Tr. 263, 264). The "termination charges" portions of the estimates shown in Exhibit 22 were apparently figured at 10% of the escalated value of the Westinghouse contract (3 Tr. 250-251) and at 10% of the unescalated value of the "balance of plant," contracts (3 Tr. 251). The *total* (not just the termination charge portion) estimated cost for the G. E. contract ($3.8 million) was figured at 10% of the unescalated value of that contract, in recognition of G. E.'s standard practice (3 Tr. 257-258).

As yet, G. E.'s estimate for the cancellation costs on its contract is very close to that of NSP.[29] This is not the case for Westinghouse and the "balance of plant" vendors. The combined claims of these two groups are running at about

[28]SNUPPS is an organization composed of several electric utility companies, including NSP, formed to adopt a standardized nuclear plant design and engineering in order to reduce costs.

[29]The various contractors at first filed *estimates* of their claims in the Spring of 1979 but about one year later they filed *claims*. Their claims generally far exceeded their initial estimates.

twice that estimated by NSP in this proceeding (2 Tr. 136, 184). While NSP's estimates of termination charges based on the value of the contracts, rather than on the value of the work performed to date of cancellation, may seem rather high,[30] they were prepared with the advice and assistance of counsel and outside consultants and the claims filed with NSP are running about double NSP's estimates filed here.[31] Recognizing that vendor claims may represent merely settlement figures for negotiation purposes which NSP itself will

[30]The underlying contracts are not very specific on how termination charges shall be computed. Thus the Westinghouse contract (Ex. 20, Article XIV) calls for payment of "reasonable and proper termination charges" which will "include a portion of the Contract Price reflecting the amount of work completed at the time of termination plus the expenses associated with the termination, including any additional expense incurred by reason of termination by Westinghouse of any of its agreements with its Suppliers."

The "balance of plant contracts" (*e.g.*, Ex. 21) state that NSP may "terminate this agreement as to all or any portion of the goods then not shipped, subject to an equitable adjustment between the parties as to any work or materials then in progress. . . ."

The contract with G. E. (Ex. 23, Article II) provides that NSP may "terminate this agreement as to all or any portion of the goods then not shipped, subject to an equitable adjustment between the parties as to any work or materials then in progress. . . . Seller shall be entitled to reasonable and equitable termination charges including Seller's direct and indirect costs, plus profit on the pro rata portion of the work completed to the date of termination. Such charges shall be consistent with the Seller's standard accounting and billing practices. . . ."

[31]An audit prepared by the Bureau of Audits of the Wisconsin Public Service Commission for use in a proceeding now pending before that Commission recommended a reduction of some $10 million in NSP's estimated cancellation loss (Ex. 53, pp. 14-15; 7 Tr. 1107-1108, 1117-1119). However, the recommendation was merely based on the opinion of the witness, Mr. Darwin, without any hard facts, that NSP's estimate was too high (7 Tr. 1107-1108; Ex. 53, pp. 14-15) and was not thoroughly tested in this proceeding. The recommendation to the Wisconsin Commission was apparently made prior to the 1980 filing of claims by the vendors which were about double NSP's estimate. The Wisconsin Commission has not acted on the recommendation, so far as this record shows. In any event, the witness would permit NSP to recover, dollar for dollar, its actual, prudent, cancellation costs and would permit the use of estimates in the write-off (Ex. 53, p. 14; 7 Tr. 1118).

prudently seek to reduce, still it does not seem reasonable to severely reduce NSP's estimates as urged by the Intervenors. This is so particularly here where NSP's estimates will be adjusted to conform to the amounts NSP will actually and prudently expend in satisfaction of those claims.

Second, Intervenors contend that by permitting the use of estimates in the write-off NSP will have no incentive to reduce its actual expenditures in satisfaction of vendor claims below the estimates. However, NSP will be held to the standard of necessary, reasonable and prudent expenditures for the vendor claims and the periodic reports with this Commission and the affected State regulatory commissions, and the conditions (part D, *infra*) which will be directed herein, should help ensure that this standard is observed.

Third, Intervenors' apprehension that permitting the use of estimates in the write-off will result in overpayments or prepayments, is groundless. The targeted ten-year write-off period will make it virtually certain that estimated expenditures will be converted to actual expenditures during that period, since no one here contemplates that vendor claims will still be outstanding after ten years. Moreover, assuming a $70 million write-off amount to be amortized in ten years, or $7 million per year, it will take five years to write-off the $35 million in actual expenditures NSP has already made, and the estimated expenditure portion of the write-off will not be reached until the sixth-tenth years, by which time all the estimated expenditures will most probably have been converted to actuals.

Fourth the discussion in subsections C and D of this section, below, on the variable amortization period and the various conditions directed herein to the write-off authoriza-

tion, should make it clear that NSP will not be permitted to write-off more than its reasonable, actual, prudent cancellation expenditures.

Fifth, Intervenors' contention that losses may not be amortized until they are paid has been sufficiently answered above. Moreover, since under their contention the numerous vendor claims would be settled at different times, each claim or group of claims would have a different starting and ending amortization period. This could lead to an administrative morass both for NSP and the regulators. The use of reasonable cancellation cost estimates and the variable amortization period, with the various conditions adopted herein, is far preferable.

3. Treatment of AFUDC

Included in NSP's estimated $75 million cancellation loss which it seeks to amortize is AFUDC accrued to the date of project termination in March, 1979. AFUDC (both the debt and equity portions thereof) amounts to $4,869,293, of which, according to NSP, the common equity portion is $3,132,347[32] (Ex. 37).

NSP claims that it is entitled to write off the entire amount of AFUDC. This position is supported by Mr. Darwin, a witness for Intervenor the Wisconsin Public Service Commission, who did not purport, however, to speak for that Commission, which did not address the matter in its briefs. The Staff of FERC and the Minnesota Cities would exclude all AFUDC from the write-off. The Minnesota-Dakotas Commissions and the Wisconsin Cities recommend exclusion of only the common equity portion of AFUDC. We adopt that recommendation.

[32]The Minnesota-Dakotas Commissions compute the common equity portion as $3,201,900 (Initial Br., pp. 73-74).

In Opinion No. 49,[33] this Commission held that Nepco was not entitled to a return on the unamortized balance of the cancellation loss there at issue. In balancing the interests of ratepayers and investors and allocating the risk of loss on an aborted project between these two groups, the Commission (adopting the language of the Initial Decision) stated (mimeo, at 30):

Ratepayers are not required to insure that a utility receive a return on all monies invested in the enterprise; ratepayers are required to pay a return on only those investments in properties that are used and useful in the public service.

The common equity portion of AFUDC represents a return to investors even though for accounting purposes, as argued by NSP, it may be considered to be a construction cost. (*See* Uniform System of Accounts, Electric Plant Instructions) (17); 18 CFR, Part 101.) Unlike the debt portion of AFUDC or the preferred stock portion, which reflect out-of-pocket expenditures for debt interest or a contractual commitment to pay preferred stock dividends, the common equity portion of AFUDC represents a return to the common stockholders for which NSP is not out-of-pocket and is not under any contractual obligation. While Opinion No. 49 did not specifically deal with AFUDC, the reasoning of the Opinion makes it clear that the risk of non-recovery of a return on the common equity investment made during construction of an aborted, non-completed project must be borne by the common stockholders and not by the ratepayers.

Thus, here, the common equity amount of AFUDC must be excluded from the write-off. That amount is correctly

[33]*New England Power Company* ("Nepco"), Docket Nos. ER76-304, *et al.*, Opinion No. 49, issued July 19, 1979; Opinion No. 49-A, issued March 26, 1980.

computed as \$3,201,900 by the Minnesota-Dakotas Commissions (Initial Brief, pp. 73-74), rather than as \$3,132,347, figured by NSP (Ex. 37).[34] Since this amount to be excluded from the write-off is only about 4% of the write-off as estimated by NSP, it is readily apparent that the ratepayers will bear a far greater portion of the Tyrone cancellation loss than the stockholders. The latter will be recouping all their investment in the Tyrone project which will never be used and useful to the customers, albeit they will not and should not earn a return on their common equity investment in the project.[35]

The foregoing sufficiently answers the position of the Staff and the Minnesota Cities that all of AFUDC (and not merely the common equity portion thereof) should be excluded from the write-off. For the carrying charges on the AFUDC debt and the contractual commitment to pay AFUDC preferred stock dividends are not risks which are to be allocated to the NSP stockholders under the rationale of the *Nepco* decision, Opinion No. 49. Moreover, Staff's and Cities' argument based on the "used and useful" theory would place the risk of the *entire* cancellation loss on the NSP stockholders, a result contradicted by the *Nepco* decision.

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[34]The computation by the Minnesota-Dakotas Commissions is included in their initial brief, to which NSP made no objection in its reply brief.

[35]In contrast, where gas supply projects have been aborted, stockholders have been required not only to absorb a part of AFUDC but the *entire* cancellation loss as an entrepreneurial risk properly borne by the stockholders. *Tennessee Gas Pipeline Company*, Opinion No. 624, 48 FPC 149 (1972), *aff'd.*, *Tennessee Gas Pipeline Company v. FPC*, 487 F.2d 1189 (D.C. Cir. 1973); *Transcontinental Gas Pipe Line Corporation*, Opinion Nos. 801, 801-A, *aff'd.*, *Tennessee Gas Pipeline Co. v. FERC*, 606 F.2d 1094 (D.C. Cir. 1979), *cert. denied*, 100 S.Ct. 1284 (1980); *see also*, *Columbia Gas Transmission Corporation*. Opinion No. 101, November 6, 1980. In the instant case, probably because of the *Nepco* decision, Opinion No. 49, *supra*, no party claims that the entire cancellation loss must be borne by the NSP stockholders.

NSP's arguments against excluding common equity AFUDC from the write-off are not persuasive. Even if accounting convention or the Commission's Uniform System of Accounts treats such AFUDC as a cost rather than a return, they do not govern ratemaking. They do not answer the question at issue, namely, how to assign or allocate the risk of nonrecovery of AFUDC in the event a project is not completed and never goes into service.[36] NSP's contentions that the result reached here will be very disturbing to the accounting profession, may result in the refusal to certify a utility's financial statements, and may require the use of CWIP in rate base, are hyperbole. Mr. Hahne, the accounting witness who foretold such dire results, was not even aware that the Commission had refused to permit the recoupment of any and all cancellation costs, including AFUDC, on aborted projects on the gas supply side (2 Tr. 87-89). Moreover, the fact that AFUDC is booked[36a] as income in a utility's financial statement, does not mean that the Commission must guarantee the recovery of AFUDC if the underlying project is aborted, any more than an allowed rate of return is a guarantee that the company will actually earn such a return, or than the Commission must allow rate recovery of imprudently incurred costs merely because they have been booked.

[36]Electric Plant Instructions, 3(17) (18 CFR, Part 101 Instructions 3(17) state in part:

> "No allowance for funds used during construction charges shall be included in these accounts upon expenditures for construction projects which have been abandoned."

[36a]NSP's attempted distinction between common equity AFUDC accrued up to the date of project cancellation and that accrued thereafter, allowing recoupment of the former but not the latter, must fail since, among other things, it could result in improvidently delaying necessary project cancellation.

Respecting the allocation or risk of non-recovery of AFUDC, NSP argues that the NSP stockholders will be absorbing about $22 million of its estimated $75 million loss since the amortization period began in March 1979 and, on the average, NSP did not get any rate increases until more than a year later (Ex. 7). However, this assumes a five-year amortization period; doubling that period, as targeted herein, presumably would cut the putative $22 million loss in half. Moreover, NSP assumes that its rates would be adjusted downward immediately at the end of the amortization period to eliminate any recovery for the write-off. This is an assumption which may not accord with reality. Of course, if NSP is willing to stipulate for a $22 million reduction in the write-off, its argument for inclusion of the $3.2 million in equity AFUDC would most likely be better received. However, NSP has not come forward with any such stipulation. Finally, NSP's choice of the March 1979 rate for commencement of the write-off period and the year or more later dates for rate increase applications, were choices voluntarily made by NSP itself and may have been influenced by its calculation that its economic and financial performance were such as to militate against any earlier rate increase applications. In any event, even assuming a $2 million cancellation loss-absorption by the stockholders, plus a $3.2 million non-recovery of equity AFUDC, the ratepayers will still be absorbing double the loss of the stockholders and that ratio will be still more unfavorable if the loss exceeds $75 million.

On all the foregoing, it is found and concluded that $3,201,900 representing the common equity portion of AFUDC must be eliminated from the write-off.

C. The Amortization Period

All parties agree that the Tyrone cancellation loss should be amortized over a number of years. They also agree, consistent with Opinion No. 49, *supra,* that no return or carrying charges on the unamortized balance may be recovered by including the same in rate base or otherwise. They present four competing treatments for the write-off period.

NSP proposes a five-year amortization period. NSP witness Thorsen testified that sound accounting practice requires the write-off of a non-productive asset as quickly as possible consistent with a reasonable impact on ratepayers (3 Tr. 391). This impact, assuming a $75 million write-off amount and a five-year, write-off period, amounts to an increase in revenue requirements of 1.5% to 2.0% for NSP-M's retail customers, 1.6% to 2.0% for NSP-W's retail customers, 1.8% to 2.5% for NSP-M's resale customers and 2.3% to 2.8% for NSP-W's resale customers (3 Tr. 366-367).

NSP points out that by beginning the amortization period on March 6, 1979, and not filing for a rate increase until more than a year later, the company will have absorbed $22 million of the loss without passing it along to ratepayers.[37] NSP argues that it would be unfair to use a longer amortization period since the Company would have to bear the carrying charges associated with the loss along with the portion of the loss the company has already absorbed.

NSP claims that a five-year amortization would lead to rate stability because the amortization could be completed,

[37]This argument is discussed, above (at p. 25).

or nearly completed, by the time its Sherburne County No. 3 coal-fired generating unit is scheduled to come on line in 1984 so that rates reflecting the Tyrone amortization would not overlap to a major extent with the rates reflecting the Sherburne County unit in rate base. Also, the write-off will also be completed or almost completed by 1984 when NSP will begin to incur major capital expenditures on its proposed new coal-fired generating project (3 Tr. 367).

The Wisconsin Public Service Commission witness, Mr. Darwin, supports NSP's five-year amortization period[38] (7 Tr. 1097).

The Commission Staff has proposed what it calls a variable amortization period over which to amortize the loss (see p. 18, *supra*). Witness Der explained that this amortization method consists of the NSP estimated loss figure (reduced by AFUDC) collected in equal increments over a targeted ten year period. The variable feature of this scheme is that while the same amount will be written-off each year, the amortization period will be lengthened or shortened depending on whether the actual loss is greater or less than the estimated loss. For example, if the actual loss is one tenth greater than the estimated loss, the amortization period would be lengthened one year (9 Tr. 1305-1306, 1351-1355). The converse would also apply.

Staff maintains its proposal would encourage NSP to settle vendor claims quickly and at the best price since any lessening of the estimated figure will shorten the amortization period and therefore lower NSP's carrying costs. High settlements would have the opposite effect. Additionally, Staff believes that its method will prevent overcollection or

[38]The witness did not purport to state the position of the Wisconsin Commission, which did not address the matter in its briefs.

prepayment of the loss. By extending the period to a targeted ten years it would appear that all amounts will be known and written-off within the period. NSP's rates would then more clearly reflect actual cancellation costs rather than estimates. Finally, Staff contends that the stability of the amortization figure will lead to rate stability. The same amount will be collected annually, there will be no need for adjustments to this figure.

The Public Service Commissions of Minnesota, North Dakota and South Dakota propose a thirty-year amortization period. Their witness Towers testified the thirty-year period should be adopted because thirty years was to be the useful life of the project (7 Tr. 971). He maintained that if the plant had been constructed it would have been reflected in rates for thirty years (5 Tr. 643) and thus the thirty-year period will collect the write-off from those ratepayers whom the plant was intended to serve (9 Tr. 1360).

The Wisconsin Cities propose a fifteen-year amortization period. They base this period on a comparison with the rate effect the Commission found to be reasonable in Opinion 49, *New England Power Company, supra.* Witness Sack in calculating the amount of the instant loss, amortized by the rate effect projected in *New England* (.94%), arrived at a result of fifteen years (Ex. 52). The Wisconsin Cities echo the fears of Staff that a five year period will result in overcollections or prepayments. They urge a longer period to guard against any such result.

We conclude that the Staff's variable amortization period targeted at ten years should be adopted. In *New England Power Company*, Opinion 49, the Commission found that the amortization period for a cancelled project "is a close question which involved delicately balancing the interests

of investors and ratepayers." (Mimeo, at page 32). The reasonableness of the period and its impact on ratepayers were major concerns of the Commission *(Ibid.)*.

The Staff's proposed variable amortization period best meets these criteria. It protects the ratepayers from overpayment and prepayment on the one hand and allows the Company a shortened amortization period on the other if it is able to bring down the cost of the loss from the estimates. This method will reflect losses that are known, not estimated. The lengthening of the targeted period from five to ten years and, in effect, affording the company an incentive to settle vendor claims quickly and modestly should produce these desirable results. Staff is also correct in pointing out that the formula will result in rate stability. Each year that the formula is in effect its impact on rates will not change. No adjustments are required. Finally, this method will not result in an undue burden on ratepayers. The effect will be approximately one-half that of the company's proposal.

NSP's proposed period includes too great a danger of precollection from ratepayers. Due to the uncertain nature of the estimated loss and uncertainty as to when all vendor contracts will be settled a five year period is not sufficient. The balancing of investor and ratepayer interests militates against this proposal.

The State Commissions' proposal of a thirty-year amortization period is not accepted. An amortization period tied to the useful life of the plant had it been built is not an appropriate criterion, and it has been rejected in Opinion No. 49. This plan unduly burdens the Company since it would have to bear carrying the charges on the loss for an unreasonably long period. No good reason appears for

burdening ratepayers thirty years hence with a loss which occurred currently. Moreover, the State Commission's proposal would depart from good accounting principles that a non-productive asset shall not be carried on the Company's books for an unreasonable period. No authority or example can be found to support this proposal.

The Wisconsin Cities' fifteen-year amortization proposal is likewise rejected. In determining the amortization period other factors then ratepayer impact are also important. Slavishly adopting the impact used in the *New England* Opinion No. 49 is not a sufficient basis for formulating the amortization period. The Commission in that Opinion said nothing in the nature of requiring that a 0.94% rate impact shall be used as the maximum for loss amortization in other cases. Moreover, the total customer impact under the variable amortization period is consistent with that in *Nepco.* The balancing of investor and ratepayer interests mandated in Opinion No. 49 requires a rejection of Wisconsin Cities' fifteen-year amortization period.

Having found and concluded that NSP's estimated Tyrone cancellation loss of $75 million, reduced by $3,201,900 for the common equity portion of AFUDC (*i.e.,* $71,798,100), shall be used for the targeted or tentative write-off and that said amount shall be written-off or amortized (without any return or carrying charges) in the targeted or tentative ten-year write-off period, NSP is permitted to amortize the sum of $7,179,810 each year. Since the total amount to be amortized depends, at least in part, on the actual, prudent amounts in settlement of vendor claims and salvage, the period during which NSP will continue the $7,179,810 write-off will depend on such settlements and salvage. Thus, for example, if NSP's actual,

prudent cancellation loss expenditure is one-tenth greater, or one-tenth less, than the $71,798,100 estimate, the write-off period will be eleven years, or nine years, respectively.

D. Conditions to the Write-Off Permission

In light of the discussion above, the write-off permission granted herein is made subject to the following conditions designed to ensure that only reasonable and prudent cancellation loss expenditures shall be amortized.

1. NSP shall report quarterly to FERC and the Intervenors the progress of its vendor settlements and salvage, and how the same compares with its estimates, such reports to contain such data as may be required by the Staff of this Commission.

2. NSP may not write-off or reflect in jurisdictional rates an amount for the write-off which is in excess of $7,179,810 per year or a total of $71,798,100, without the express written approval of this Commission.

3. NSP shall take such action as may be required by this Commission to ensure that the write-off and the jurisdictional rates reflecting such write-off, do not recover more than the NSP actual, prudent expenditures for the Tyrone cancellation loss, and to refund to its customers any amounts recovered from them which are in excess of such expenditures.

V. Accumulated Deferred Income Taxes Resulting from the Cancellation Loss

Consistent with the decision in *New England Power*, Opinion No. 49, NSP will amortize the gross amount of the

Tyrone cancellation loss, rather than the net, after tax, amount of the loss.[39] NSP agrees, as required by Opinion No. 49, it will not earn a return on the amortized balance of the loss by including the same in rate base. For income tax purposes, NSP deducted the gross amount of the loss in its tax return for 1979, thus reducing its federal and state income taxes by $37.5 million from what such taxes would have been absent the loss. NSP proposes to credit its deferred income tax account No. 283, with the $37.5 million (Ex. 6; 4 Tr. 440-441). NSP has not flowed through the $37.5 million to the ratepayers in rates but intends to normalize the benefits of this tax deduction and flow it back to the ratepayers over the amortization period for recovery of the loss (3 Tr. 369-70; 4 Tr. 441-42; Ex. 6).

Thus in a real sense the $37.5 million in deferred taxes to be credited to Account No. 283 is ratepayer contributed capital; it is derived from the rates paid by the ratepayers who have paid an income tax allowance in cost of service as through there had been no $75 million tax deduction for the Tyrone loss; clearly it has not been supplied by the NSP investors (4 Tr. 550-551, 554; 9 Tr. 1356).

For this reason, the Wisconsin Cities propose that the benefits of the income tax deduction be shared with the ratepayers who will be paying the cancellation loss and that this be accomplished by reducing NSP's rate base by the unamortized amount credited to account No. 283 (4 Tr. 549-551). The other Intervenors and the Commission Staff have taken no position on this matter. NSP opposes Wisconsin Cities proposal, arguing that since the Tyrone investment was not and will never be in rate base and since

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[39]The figures and discussion throughout the text, *supra*, have been in terms of the gross amount of the loss.

the investors will recover no return on the write-off, it would be highly unjust to accept Wisconsin Cities' proposal.

We conclude, however, that Wisconsin Cities' proposal should be adopted. The deferred tax credit to Account No. 283 represents capital contributed by the ratepayers and stems from NSP's income tax deduction for the gross amount of the loss, which deduction has not been flowed through to the ratepayers but instead will be normalized. The ratepayers will have to bear the full amount or much the greatest amount of the loss.[40] It is only just and equitable, as required in Order No. 530-B (mimeo, at p. 9), that the ratepayers be permitted to share in the tax benefits resulting from the loss deduction and normalization. This should be accomplished by reducing NSP's rate base by the unamortized balance of the deferred tax credit in Account No. 283 for the Tyrone loss. A similar result was reached by Judge Kimball in his Initial Decision in *Wisconsin Power and Light Company*, Docket No. ER77-347, September 30, 1980 (mimeo. at 22-23), dealing with a similar issue.

NSP's reliance on Judge Benkin's Initial Decision in *Virginia Electric and Power Company*, Docket No. ER78-522, June 2, 1980, is misplaced. There the company had flowed through to the ratepayers the tax benefits of the cancellation loss by electing to write-off only the net (after tax) amount of the loss, rather than the gross amount as here (I. D. at 19-22).

While NSP's argument that rate base should not be reduced by the deferred taxes credited to Account No. 283 because the underlying investment never was or will be in

[40] *See* discussion, *supra*, of NSP's argument that the investors will bear some $22 million of the loss.

rate base has a superficial ring of plausible symmetry, the argument does not withstand analysis. NSP and its stockholders will have the full use and benefit of the $37.5 million[41] tax deduction until it is flowed back to the ratepayers over the course of the ten-year or so write-off period. Since the ratepayers have paid rates which did not reflect the tax benefit of the loss deduction taken by NSP, they have contributed the capital reflected in the credit to Account No. 283 and they should share in the benefit of that tax deduction. This should be accomplished, as directed by the Commission in Order No. 530-B,[42] by reducing NSP's rate base by the unamortized balance of the amount credited to Account No. 283 as a result of the Tyrone loss tax deduction.

VI. Accounting Treatment of the Tyrone Loss

NSP has filed for approval of its proposed accounting treatment of the Tyrone cancellation loss (Ex. 6) which departs in a number of respects from the rulings made herein, *e.g.*, amount of the loss, write-off period. NSP is required to adjust its proposed accounting treatment to conform to this decision.

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[41]For example, NSP could invest the monies in interest bearing securities of other companies or in its own operations.

[42]Order No. 530-B states (mimeo at 9): ". . . as noted in Order 530-A, we shall continue our policy of deducting the deferred taxes in Accounts 282 and 283 from rate base. This will result in a sharing of the benefits of normalization with the customers of the utility." While Order No. 530-A speaks of the deferred taxes as being "related to rate base items," (mimeo at 9), the Tyrone investment is so "related" since it would have been included in rate base had the plant gone into service.

VII. Order

WHEREFORE, it is hereby ordered, subject to review by this Commission:

1. Northern States Power Company (Wisconsin) is permitted to amortize the loss arising from the cancellation of the Tyrone project over a targeted ten-year period in accordance with this decision and subject to the conditions set forth in this decision.

2. Said cancellation loss shall be allocated between Northern States Power Company (Wisconsin) and Northern States Power Company (Minnesota) in accordance with this decision.

3. There shall be excluded from the loss to be amortized, an amount reflecting the common equity portion of AFUDC, as discussed in this decision.

4. The loss which is to be amortized shall not be included in rate base.

5. The unamortized portion of the deferred taxes which must be credited to Account No. 283 by reason of the income tax deduction for the Tyrone cancellation loss shall be deducted from rate base.

6. The accounting for the Tyrone cancellation loss shall conform to this decision.

Northern States Power Company (Minnesota), Docket No. ER79-616;

Northern States Power Company (Wisconsin), Docket No. ER79-616

Opinion No. 134; Opinion and Order Finding Amendment to Coordinating Agreement Just and Reasonable with Modification

(Issued December 3, 1981)

Before Commissioners: C.M. Butler III, Chairman; Georgiana Sheldon, J. David Hughes and A.G. Sousa.

[Note: Initial Decision on Nuclear Plan Cancellation Loss was issued December 4, 1980, and appears at 13 FERC ¶63,049.]

Appearances

George F. Bruder, Albert R. Simonds, Gene R. Sommers and *David A. Lawrence* for the Northern States Power Companies.

J.H. McLoone IV for the Minnesota Municipal Intervenors, Cities of Anoka, Arlington, Brownton, Buffalo, Chaska, Granite Falls, Kasota, Kasson, Lake City, North Saint Paul, Saint Peter, Shakopee, Waseca and Winthrop, Minnesota.

Frances E. Frances, John Michael Adragna, Robert C. McDiarmid, Rodney Wilson and *Ben Stead* for the Minnesota Public Service Commission, the North Dakota Public Service Commission and the South Dakota Public Utilities Commission.

Philip Mause and *William Sloshberg* for the Public Service Commission of Wisconsin.

J. Leroy Thilly, James F. Fairman and *Robert L. Olson* for the Wisconsin Intervenors, Cities of Black River Falls, Bloomer, Cadott, Cornell, New Richmond, Spooner, Westby, Whitehall and La Crosse, Wisconsin.

Alan Wolf and *L. Jorn Dakin* for the Staff of the Federal Energy Regulatory Commission.

[Opinion No. 134 Text]

On August 24, 1979, Northern States Power Company (Minnesota) and its wholly owned subsidiary, Northern States Power Company (Wisconsin), (collectively referred to as Northern States) filed an Amendment to their Coordinating Agreement proposing to allocate costs associated with an abandoned electric generating facility (Tyrone Energy Park) in accordance with the terms provided in the Coordinating Agreement for allocating fixed costs. By order issued on October 22, 1979, we accepted the proposed Amendment, suspended it for one day, allowed it to be effective as of March 7, 1979, and set for hearing the justness and reasonableness of the Amendment.

Following the hearing and the filing of briefs, the presiding administrative law judge issued an initial decision resolving numerous issues surrounding the abandonment and the proposed Amendment. Briefs on and opposing exceptions to the initial decision were filed by Northern States, the Commission's staff, the State Commissions of Minnesota, North Dakota and South Dakota (State Commissions), a group of Wisconsin Cities, the Public Service Commission of Wisconsin and the Minnesota Attorney General's Office.

Except for those matters discussed below, we find the exceptions without merit and they are therefore rejected. We affirm and adopt the initial decision on all issues except the findings that Northern States should not recover common equity AFUDC and should reduce its rate base by the unamortized balances in its deferred tax account (Account 283) related to the Tyrone cancellation loss. In addition, we find it necessary to clarify the auditing and review procedures surrounding the estimated costs that are included within the total project cost.

Estimated Costs

At the time of the hearing, Northern States had accrued \$35 million in costs related to Tyrone and estimated that it would pay an additional \$40 million to terminate approximately 250 contracts with vendors and suppliers of goods and services for the project. The law judge concluded that estimates may be used in computing the amount of the write-off so long as they are reasonable, especially where, as here, they will be adjusted during the course of the amortization period to conform to the actual expenditures. The judge found Northern States' estimates reasonable and allowed them to be included as part of the total project cost. Deducting \$3.2 million associated with common equity AFUDC, the judge therefore found the project costs (both actual and estimated) to total \$71.8 million which Northern States was allowed to amortize over a ten year variable period. We agree with and affirm the decision to include the \$40 million estimated costs as part of the total project cost subject to adjustment as the vendor claims are settled.

The judge also noted that the costs resulting from the vendor settlements must satisfy the prudent expenditure test before they can be included in Northern States' rates. He was unable to make this assessment from the present record for obvious reasons, and therefore required Northern States to submit quarterly reports to the Commission and the intervenors detailing the terms of the vendor settlements as they occur so that this determination could be made. Northern States has since filed four reports with the Commission. In its last report (filed on November 10, 1981), it indicated that it has settled all but \$1.2 million of the vendor claims with the result that it has revised its total estimated project costs to \$67 million or \$8 million below its original

estimate of $75 million. We are not concerned by the emerging difference ($8 million presently) between the actual costs and the costs tentatively approved by the judge since the project costs ultimately to be amortized into rates will be adjusted to account for this difference pursuant to the variable amortization approach formulated by the judge and approved herein.

We are concerned, however, with the fact that the quarterly reports contain virtually no explanation as to how the settlement amounts were reached. We are simply unable to assess the prudence of the settlements solely on the basis of bottomline dollar figures. Accordingly, we direct Northern States to file a report with the Commission and the parties to this proceeding within 75 days of the issuance of this opinion detailing the terms of all vendor settlements reached prior to such date complete with all appropriate documentation and explanation necessary for us to determine whether the vendor settlements were prudent. Thereafter, Northern States shall provide such documentation when it submits its future quarterly reports until all of the vendor claims have been settled. At that time, the staff and the parties shall have 30 days to petition the Commission to conduct further inquiries into the vendor settlements if they believe Northern States has failed to adequately demonstrate the justness and reasonableness of the jurisdictional expenses which they will engender.[1] Our decision here to

[1]By proceeding in this fashion, we are able to fully satisfy the concern expressed by the Wisconsin Cities in its Motion to Strike of March 16, 1981, that the quarterly reports submitted to date provide little opportunity for an assessment of the prudence of the the settlements. We reject its other claim in the motion that the Commission may not consider the information provided in the reports (as to the actual costs incurred by Northern States in resolving these outstanding claims) when we rule on the reasonableness of the estimates since we are free to officially note objective facts which are not in the record. We therefore deny the motion.

tentatively allow the estimated costs to be included within the total project cost is in part based on Northern States representation to avail itself to further inquiry into the prudence of the settlements and to appropriate adjustments in the jurisdictional project costs approved herein if any are necessary to preclude recovery of any imprudently incurred costs.[2]

Under the procedure established above, the further inquiry, if any, into the prudence of the settlements will not commence until after all outstanding vendor claims have been settled. We wish to proceed in this fashion so that all allegations of imprudence can be considered at one time rather than in piecemeal fashion. However, since the currently actualized expenses which have been found prudent to date (approximately $35 million) will be fully amortized within five years at the rate of $7.5 million per year, it is necessary that the settlement negotiations be conducted with reasonable dispatch so that they are finalized in sufficient time to allow the potential inquiry into their prudence to be completed prior to when the costs arising from the settlements begin to be amortized. We recognize that settlement negotiations are often lengthy (especially if litigation becomes necessary) and for this reason we decline at this time to set a time limit within which the estimated costs must be actualized. However, nothing in this opinion precludes us from reconsidering the justness and reasonableness of the estimated costs and the adequacy of the above procedures at some future point should it develop that due to protracted negotiations, an assessment of the prudence of the settlements cannot be completed prior to when the estimated costs begin to be amortized.

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[2]See Northern States' brief on exceptions, page 6, and its Answer to Wisconsin Cities Motion to Strike, page 2, filed March 30, 1980.

Reducing Rate Base by Unamortized Balance in

Deferred Tax Reserve (Account 283)

In 1979 Northern States deducted the Tyrone loss from its federal taxes and thereby lowered its tax requirements for that year by $37.5 million. Northern States placed this amount in its deferred tax reserve (Account 283) in order to normalize the tax benefits over the amortization period. Normalization of the tax effects of certain timing difference transactions is required and we affirm and adopt its use here.[3]

A collateral issue raised in this proceeding is whether Northern States should also reduce its rate base by the unamortized balances in Account 283 which are related to the cancellation loss. The law judge concluded that it should on the reasoning that the $37.5 million credited to Account 283 was derived from ratepayers through the income tax component of Northern States' cost-of-service and that the ratepayers should therefore receive the beneficial use of this money. The judge further found this result required by Commissison Order Nos. 530-A[4] and 530-B.[5] We disagree with the judge's interpretation of those decisions. Furthermore, we do not agree with his conclusion that the funds lost in the Tyrone venture were, prior to amortization, derived from the ratepayers. As a result, we conclude that the initial decision must be reversed on this matter.

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[3]See "Final Rule" on tax normalization, Order No. 144, issued May 6, 1981.

[4]55 FPC 162 (1976).

[5]56 FPC 44 (1976), *remanded, Public Systems v. FERC*, 606 F.2d 973 (D.C. Cir. 1979), *reh. den.* March 30, 1979. The proceeding culminating in Order Nos. 530-A and 530-B was initiated to consider generically the interperiod income tax allocation (tax normalization) issue.

As noted, we disagree with the judge that a rate base deduction is required by Order Nos. 530-A and 530-B. In the first place, those orders were remanded to the Commission for further consideration in *Public Systems*. More importantly, and contrary to the judge's analysis, those decisions did not require a rate base deduction where, as here, the plant was never placed in service and included in rate base. In fact, those decisions stand for the opposite conclusion.

The FPC stated in Order No. 530-A:[6]

> In those instances where we approve normalization for rate purposes of the tax effect of a class of items, such deferred taxes are placed in Accounts 282 and 283, and are related to rate base items, we shall, of course, continue our policy of deducting the deferred taxes in those amounts from rate base.

The judge improperly interpreted the Commission's intention by this language to require a rate base deduction if the project investment would have been included in rate base had the project been successful. We think it clear that we intended to require a rate base deduction only if the tax benefits were related to an actual rate base item, not a hypothetical one which, but for abandonment, would have been capitalized. The judge's view must be rejected.

Order Nos. 530, 530-A and 530-B were remanded to the Commission by the United States Court of Appeals for the District of Columbia circuit for further consideration in *Public Systems*. We initiated the rulemaking in Docket No. RM80-42 in response to the remand. The Wisconsin Cities argue in their brief opposing exceptions that we established a policy in § 2.202(b)(2) of the Proposed Rulemaking issued in that proceeding which would require a rate base offset in all instances of normalization. We do not agree.

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[6] 55 FPC at 167.

On page 50 of the Proposed Rulemaking we stated that "[p]aragraph (b)(2) . . . codifies existing Commission practice with regard to rate base adjustments for accumulated deferred income tax accounts." The existing practice to which we referred was that espoused in Order No. 530-A which, as noted above, required rate base deductions only for those items actually included in rate base. Accordingly, we find nothing in the Proposed Rulemaking which supports the position of the Wisconsin Cities in this proceeding.

In the Final Rule which superseded the Proposed Rulemaking,[7] we required rate base offsets for deferred taxes recorded in Account 283 related to rate base, construction or other jurisdictional activities (codified in § 2.202(b)(2) of the Commission's regulations). Subsequent to issuance of the Final Rule, however, we granted rehearing of Order for purposes of further consideration.[8] There, we stayed Order No. 144 pending an order on rehearing in those dockets. The order on rehearing has not been issued as yet and thus the legal effect of Order No. 144 has been and remains stayed. To the extent Order No. 144 may be inconsistent with this opinion, the inconsistency (if any) will be addressed in the rehearing of Order No. 144.

Having thus disposed of the argument that precedent requires the rate base deduction, it is necessary for us to address the merits of whether one is appropriate in this case. The law judge felt the ratepayers should receive the time value use of the deferred taxes during the normalization period since the $37.5 million placed in Account 283 was,

[7]Order No. 144, issued May 6, 1981.
[8]See order issued in Docket Nos. RM80-42, R-424 and R-446 on July 2, 1981.

in his opinion, derived from them. We agree with the judge that the party which contributed the corpus of the Account 283 deferred tax reserves should enjoy its use until fully normalized. However, we disagree with his conclusion that this party was the ratepayers.

It is clear that the funds used by Northern States during the pre-certificate period were derived solely from the investors. The ratepayers made no contribution prior to abandonment. Over the course of the amortization period the ratepayers will gradually reimburse Northern States for its investment. But this contribution will be offset each year by commemsurate portion of the normalized tax benefits. In this fashion, the revenue requirements and the associated tax benefits will be reflected in rates in direct proportion.

These conclusions are uncontroverted by the record and we do not interpret the law judge as having reached a contrary conclusion in the initial decision. Rather, it appears that his holding is based on the fact that Northern States' overall tax requirements are paid entirely by the ratepayers through their contribution to the income tax component of the cost-of-service. This amount, according to the judge, in part reflects revenues related to Tyrone. We disagree. Since the Tyrone project was never placed in service and its cost was never included in rate base, Northern States will not earn a return on its Tyrone investment, will not have a corresponding tax obligation, and will neither need nor receive related tax compensation from its ratepayers. To deduct the unamortized deferred tax reserve balances from rate base would create a negative rate base and would therefore lower Northern States' cost-of-service by $15 million over the course of a ten-year normalization period. Were we to allow this to occur, we would effectively

deprive Northern States from receiving compensation for its entire out-of-pocket investment in Tyrone contrary to the policy we found to be in the public interest in Opinion No. 49.[9] We have been shown no reason to alter the balance that decision struck and we decline to do so indirectly here through a rate base deduction.

Nor do we see any inequities in allowing Northern States to receive the use of the Account 283 balances. Since it will lose the time value use of its investment during the amortization period, it follows that it should receive the time value use of the unamortized tax benefits related to that investment during the normalization period. This type of parity of treatment is no different than that employed when we assigned the actual tax benefits to the ratepayers in direct proportion and over the same period of time during which they will incur the actual project costs.

AFUDC

Included in Northern States' estimated total cancellation loss is $4,869,293 for AFUDC accrued to the date of project termination in March 1979. Of this amount, $3,201,900 represents AFUDC related to the investment of common equity shareholders. Unlike the debt and preferred stock portions of AFUDC (for which, according to the judge, Northern States is contractually obligated to pay interest and declare dividends, respectively), Northern States will not be out-of-pocket if it is unable to collect the common equity AFUDC since it has no obligation to compensate those stockholders for the carrying costs associated with

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[9]New England Power Co., issued July 19, 1979, *aff'd in part and remanded on other grounds, NEPCO Municipal Rate Committee, et al., v. FERC, et al.*, No. 80-1343 (D.C. Cir. October 15, 1981).

their investment during construction. Finding this significant, the judge rejected the traditional view that common equity AFUDC represents a real cost of construction, concluding instead that it constitutes a return on the stockholders' investment during the pre-certificate period. Based on his reading of Opinion No. 49, the law judge therefore excluded the common equity AFUDC from the Tyrone project costs which Northern States could include in its rates.

We disagree with the judge's interpretation of Opinion No. 49 and therefore reverse his decision to deny the equity AFUDC. In Opinion No. 49 we concluded that abandoned project costs should be equitably allocated between ratepayers and shareholders and, in order to implement that view, we determined it to be in the public interest for NEPCO to amortize its recorded costs of construction but that it should not earn a return on those costs by including the unamortized balances in rate base during the amortization period. Other than to examine NEPCO's expenditures in the Salem-Harbor project to insure that they were prudent, we found it unnecessary to analyze the conceptual make-up of those costs in the fashion which the judge has assessed Northern States' expenditures in the Tyrone project. It was our conclusion there, which we reaffirm here, that the recorded construction costs which accrue during the period when the project is still viable and ongoing should be recovered through amortization.[10] A review of the record in Docket Nos. ER76-304, *et al.*, demonstrates that all forms of AFUDC were included in the approximately $13 million

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[10]AFUDC is considered a recorded cost of construction under our Uniform System of Accounts. 18 CFR Part 101, Electric Plant Instructions, Item 3 (17).

Salem-Harbor project costs which NEPCO was allowed to amortize.[11]

We think it entirely appropriate to allocate the carrying costs accruing prior to abandonment to the ratepayers and those pertaining to the amortization period to the utility. Prior to when a project is abandoned, it is clear that the carrying costs on investment are as much a legitimate expense of the project as are the more tangible costs such as parts and materials. After abandonment, all prudent expenses associated with the project, regardless of their nature, can be calculated and amortized in cost-of-service. The carrying costs which arise during the amortization period, however, are not, properly viewed, related to the project, but are part of the utility's overall financing costs. It was these costs which we allocated to the shareholder in Opinion No. 49 as part of the equitable balance struck in that Opinion. Were we to also require the shareholder to shoulder part of the AFUDC, it is clear that the risk of investing in electric utilities would be increased and the cost of capital would increase to the extent necessary to compensate for the additional risk.[12]

Further, we find it quite disturbing that the judge singled out one component of construction cost (equity AFUDC) for disallowance from amortization. Equity AFUDC has traditionally been considered a component of construction cost and a very large portion of a utility's reported income results from its capitalization. For many utilities AFUDC is more than 50 percent of reported income. The only justification for the capitalization of equity AFUDC under gen-

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[11]See Tr. 440 and Exhibit No. 88, Schedule 2, p. 6. See also p. 10 of the rebuttal testimony of William S. McDade.

[12]See Opinion No. 49, *mimeo* at 33.

erally accepted accounting principles is that ratemaking processes recognize the capitalized amounts as a legitimate construction cost and as such will ultimately be recoverable from customers as the asset to which it relates is depreciated and recovered in rates. Investors and other readers of the financial statement of utilities have relied on these reported earnings over the years on the assurance that these capitalized amounts represent valid assets. If the Commission were to single out the recorded equity AFUDC amounts from other components of construction cost, investors and other readers of financial statements would be justified in discounting the reported earnings of utilities even more than they presently do due to the non-cash nature of earnings attributable to AFUDC. This could have grave consequences to an already troubled electric industry and would not serve the public's interest in reliable service.

For all of these reasons, the initial decision must be reversed on this matter.

The Commission Finds and Orders:

(A) The Amendment to the Coordinating Agreement of Northern States Power Company (Minnesota) and Northern Power Company (Wisconsin) filed with the Commission on August 24, 1979, is just and reasonable. It is approved as a rate schedule change pursuant to §205 of the Federal Power Act subject to the modification ordered in Paragraph (B) below.

(B) The initial decision issued in this proceeding on December 4, 1980, is affirmed in part and reversed in part in accordance with this opinion.

(C) Northern States shall file with the Commission and the intervenors within 75 days of the issuance of this opinion a detailed explanation of all vendor claims which have been

settled by that date. Thereafter, it shall submit such documentation with its quarterly reports until all of the vendor claims have been settled. Any party (including the staff) which believes that the vendor claims have been imprudently settled, will have 30 days after filing of the final quarterly report to petition the Commission to conduct a further inquiry into that matter.

WHOLESALE FIRM POWER SERVICE

Service: This schedule provides for the sale of Firm Power Service by NSP to municipalities.

Service Conditions: NSP shall provide all the municipality's power and energy requirements which will be delivered hereunder at one of the following voltages:

a. Primary Distribution Voltage. The Company shall provide the substation and all the required associated facilities for a single point of delivery at City's primary distribution voltage.

b. Transmission Voltage. The City must provide the substation and all the required associated facilities to step down the transmission system voltage from 69 kV and above to City's primary distribution voltage.

Rate:

Customer Charge per Month	$116.00
Demand Charge per Month	
Production and Transmission Demand Charge - Per KW of Billing Demand	$ 4.60
Distribution Subetation Facilities Charge - Per KW of Billing Demand	$ .50
Energy Charge per Month	
All KWh - per KWh	2.128¢

(Continued on following sheet)

Rate Code

Primary Distribution		Transmission
Municipality	Non-Associated Utility	
PA014	PB014	PA024

WHOLESALE FIRM POWER SERVICE (Continued)

Monthly Minimum Charge: The customer charge plus the distribution substation facilities charge if applicable.

Late Payment Charge: The above rate plus 4% is applicable upon bills not paid within 30 days from the date bill is rendered.

Determination of Billing Demand: The demand in kilowatts for billing purposes shall be the greatest 15-minute measured load, measured at the point of metering, during the month for which bill is rendered. In no month shall the demand to be billed be considered as less than 50 percent of the highest demand billed during the previous 11 months.

Determination of Energy Charge: The kWh per month for billing purposes shall be the energy requirements at the point of metering for the current billing period.

(Continued on following sheet)

WHOLESALE FIRM POWER SERVICE (Continued)

Fuel Clause: There shall be added to or deducted from the net monthly bill an amount per kilowatt-hour equal to the product of the increase above or decrease below .906¢ in the fuel cost per kilowatt-hour sales and the loss factor of .9754 rounded to the nearest .001¢.

The fuel cost shall be the sum of the following for the most recent two-month period:

a. The fossil and nuclear fuel consumed in the Company's generating stations as recorded in Accounts 151 and 518.

b. The net energy cost of energy purchases as recorded in Account 555 exclusive of capacity or demand charges, when such energy is purchased on an economic dispatch basis.

c. The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (b) above, less

d. The fuel-related costs recovered through intersystem sales.

The kilowatt-hour sales shall be all kilowatt-hours sold excluding intersystem sales for the same period.

Fixed Rate Contract Provision: Nothing contained herein shall be construed as affecting in any way the right of the party furnishing service under this rate schedule to unilaterally make application to the Federal Energy Regulatory Commission for a change in rates under Section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder.